COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Boston Edison Company,	)	
Cambridge Electric Light Company,	)	**D.T.E. 03-121**
Commonwealth Electric Company,	)	
d/b/a NSTAR Electric	)	

INITIAL BRIEF

OF

THE ENERGY CONSORTIUM

AND

THE NE DG COALITION

Roger M. Freeman
Robert M. Granger
FERRITER SCOBBO &
RODOPHELE, PC
125 High Street
Boston, MA 02110
(617) 737-1800

Date: June 4, 2004

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Boston Edison Company,	)	
Cambridge Electric Light Company,	)	D.T.E. 03-121
Commonwealth Electric Company,	)	
d/b/a NSTAR Electric	)	

INITIAL BRIEF OF THE ENERGY CONSORTIUM AND THE NE DG COALITION

The members of The Energy Consortium ("TEC")[1] and the NE DG Coalition ("NEDGC")[2] hereby submit this Initial Brief.

INTRODUCTION

A. Summary of the Proposed Rates

In this proceeding Boston Edison Company, Cambridge Electric Light Company and Commonwealth Electric Company ("Companies" or "NStar Electric") seek approval of tariffs designed to establish standby rates for large and medium commercial and industrial customers who have their own onsite self generation facilities. The Companies based their standby rates on their otherwise applicable rate schedules (Rate G2, Rate T2 and Rate G3) for customers who do not have onsite generation. *Exhibit NStar-HCL-1* at 16.

[1] The Energy Consortium and five named members, Harvard University, Polaroid Corporation, Massachusetts Institute of Technology, Acushnet Company, and Shaw's Supermarket (collectively "TEC").

[2] American DG Inc., Aegis Energy Services Inc., OfficePower, L.L.C., Equity Office Properties Trust, Inc., Northern Power Systems, Inc., RealEnergy, Inc., Tecogen Inc., and Turbosteam Corporation.

The Companies assert that their otherwise applicable rate schedules are appropriate for designing standby rates because standby customers cause costs to be incurred by the Companies in the same manner as customers without onsite generation. *Id*. The evidence presented in the case demonstrates this assertion to be false and incomplete. First, as discussed in Section I, the otherwise applicable rates are not a sound basis for the design of new standby rates, and even if the costs incurred to serve DG customers and those without DG were the same, the proposed rates fail to take into account the benefits that distributed generation offers the distribution company. Even NSTAR Electric's expert witness concedes that such benefits exist in certain circumstances and should be accounted for. *6 Tr. 1084-1087.*

The Companies further assert that customers with onsite generation take service only infrequently. *Id.* As a result, the Companies argue, the as-used demand and energy charges applicable to customers without onsite generation do not provide sufficient revenues to cover the cost of providing service to customers with onsite generation. *Id.* This assertion is made without any factual proof and the Company goes so far as to assert that proof of this assertion is not necessary. *Exhibit NSTAR HCL-7* at 11. In addition, the only actual data regarding the load characteristics of DG Customers in evidence in the case demonstrates that the assertions of the Companies are not accurate.

In order to collect the alleged shortfall, the Companies propose that standby customers contract for a fixed level of demand ("contract demand") which reflects the generating capability or expected output of the customers' onsite generation facilities. *Id.* at 18. This proposal for contract demand flies in the face of prior Department decisions regarding standby service. See *Cambridge/MIT*, D.P.U. 94-101/95-36, p. 47 (1995).

The Companies propose to charge a customer with onsite generation a standby charge equivalent to the distribution demand charge for the otherwise applicable rate schedule multiplied by the customer's contract demand. In addition, the Companies propose to charge a customer with onsite generation a supplemental demand charge equivalent to the distribution demand charge for the otherwise applicable rate schedule multiplied by the kilowatt demand measured at the Companies' meter. *Id.* at 22. This supplemental charge, which is based on the metered demand, is in addition to the standby charge.

The Companies propose to provide a credit against the customer's metered demand to the extent that the customer's generation has reduced output at the time of the customer's monthly maximum demand. *Id.* This credit against the metered demand only applies in those months when the customer's onsite generation is out of service at the time of the maximum monthly demand. If the customer's generation is out of service at any other time during the month or is not out of service at all, the customer receives no credit for the standby demand capacity it has already paid for. Rather, the customer is charged the full standby charge based on the contract demand and the full supplemental charge based on demand as measured at the customer's meter. Thus, although the customer pays a standby charge each month based on its contract demand, the customer only receives credit for that payment in those months in which its onsite generation is actually out of service at the time of the customer's maximum demand.

The Companies proposed in their testimony to offer non-firm service on an interruptible basis based on special contracts to be negotiated. In Section III we demonstrate why the Companies' proposal is flawed and argue that the Companies' proposal regarding non-firm service should be rejected. Alternatively, the Companies should be required to offer a new Dispatchable DG service, to capture and recognize the value that DG Customers can provide the Companies under certain conditions.

B. <u>Distributed Generation</u>

Distributed generation or "DG" generally refers to the generation of electricity at the point of end use: be it the factory, the hospital, the office building or the home. Distributed generation systems comprise a wide range of technologies, fuels and sizes, ranging from solar systems with output measured in watts, to gas-fired turbines comprising 20 megawatts (MW) or more. In between these extremes are wind powered systems, reciprocating engine gen-sets, back-pressure turbines, fuel cells, micro-turbines and myriad others.

Distributed generation is typically designed to meet the needs of the end user. These needs vary from the need for clean, reliable power, to serving or utilizing thermal energy loads, to providing base load energy or peak-shaving capability, to providing back-up power generation. One thing that is clear is that there is no "typical" distributed generation system. Assumptions applicable to one type of distributed generation will not apply to others. Several witnesses testified that the majority of customers who install DG will seek to remain interconnected with the distribution system. *Casten 3 TR 417.* As a result, utilities will often be asked to provide backup, supplemental and other ancillary services. Hence, the need for so-called "standby" rates.

Distributed generation represents the vanguard of energy innovation and often results in a cleaner, less expensive and more efficient energy alternative when compared to the traditional central station generation model that dominates the energy sector today in Massachusetts and nationally.[3] Distributed generation offers benefits to the end user who installs the DG system including increased reliability, reduced fuel costs through increased efficiency, energy independence and environmental sustainability.

One of the primary benefits offered by DG is in improving energy efficiency. This factor was recognized in the recently issued Massachusetts Climate Protection Plan which states:

> Changing how and where energy is generated, and what is done with the resulting waste heat, can provide significant opportunities for efficient energy use. In combined heat and power systems, fuel is used to generate electricity. The resulting waste heat is used for heating buildings, heating water, process heating, etc. Where standard centralized power plants use roughly 40% of the fuel they burn to produce electricity, combined heat and power systems use up to 80% to produce electricity and heat. Another way of improving efficiency is to move the generation of electricity closer to where it will be used, avoiding losses during transmission. Finally, the incorporation of renewable energy into new and renovated buildings is another way to bring power closer to the end user, saving transmission losses and generating heat or electricity with little or no fuel use. The state will encourage the installation of combined heat and power applications, other forms of clean distributed generation, and the installation of new renewable energy sources through such measures as streamlined permitting and interconnection standards. *Exhibit DOER 1-19 (supp)* at 25.

In addition to the benefits accruing to the end user, distributed generation can also bring benefits to all Massachusetts energy consumers. We agree with the following general descriptions of the benefits that DG can offer to the distribution system and all consumers described by Nstar Electric's expert witness, Dr. Parmesano. *Exhibit NSTAR-HSP-1* at 3. Distributed generation can increase competition and reduce market prices, particularly in load pockets. *Id.* DG can reduce air pollution and increase fuel diversity. *Id.* at 3-4. DG can relieve congestion on the transmission system and lower energy costs.

---

[3] For a description of the traditional electric system, see the testimony of Charles Salamone, Exhibit NSTAR CPS-3.

Id. at 4. Very reliable DG can enable a distribution company to defer transmission and distribution capacity expansion. *Id.*

While every DG system does not provide the same type or level of benefits, these benefits can be quantified where applicable. Mr. Casten testified to the methodology for calculation of the benefits of distributed generation. *Exhibit NEDGC 1 at 6-7; Exhibit DTE-NEDGC 1-7.* [4]

The Department has recognized the potential benefits of distributed generation and supports the deployment of distributed generation. In its *Order Opening the Investigation into Distribution Generation*, the Department stated that it "has recognized the importance of distributed generation[5] as a resource option in the restructured electric industry. [Citations omitted] The Department further stated that "Distributed Generation can meet customers' energy needs. It also has potential for load response. D.T.E. 01-54 at 11. Further, because of its ability to reduce peak load, distributed generation may relieve transmission and distribution constraints and protect against outages." See *Investigation by the Department of Telecommunications and Energy on its own Motion into Distributed Generation*, D.T.E. 02-38 (June 13, 2002)

The Commonwealth of Massachusetts also supports GC. Most recently, distributed generation has been included and advocated for in the Massachusetts Climate Protection Plan, issued by Governor Romney on May 6, 2004. The Climate Protection Plan states:

---

4 For a discussion analysis and methodology for calculating and quantifying the benefits of distributed generation, *see Exhibit DTE-NEDGC 1-7.*

5 General Laws c. 164, § 1 ("Restructuring Act" or "Act") defines distributed generation as "a generation facility or renewable energy facility connected directly to distribution facilities or to retail customer facilities which alleviate or avoid transmission or distribution constraints or the installation of new transmission facilities or distribution facilities."

> The Division of Energy Resources and the Department of Environmental Protection, in cooperation with the Department of Telecommunications and Energy, and the State Office of Building Standards, will be asked to review our existing laws and regulatory policies, and make recommendations that facilitate the introduction of distributed energy sources, giving special attention to interconnection standards for fuel cells, combined heat and power, ***standby rates***, air emission standards, and renewables. Recommendations for future legislation and regulatory streamlining are the expected outcomes of this action. *Exhibit NSTAR-DOER 1-19* at 31. [emphasis added]

In addition, in the wake of the blackout in the Northeast and mid-west last summer, Governor Romney convened a special task force to assess the reliability of the Massachusetts energy system. The Report issued by the Governor's Task Governor's Task Force on Electric Reliability and Outage Preparedness also refers to distributed generation as one of the solutions to the challenges facing Massachusetts energy sector:

> Massachusetts should explore opportunities to create, through state and regional policy formulation and implementation, as well as system oversight, a more stable, more reliable electric system through investments in conservation, energy efficiency and distributed generation. Where institutional or regulatory barriers inhibit such investments, Massachusetts should seek to eliminate these barriers while protecting the interests of the ratepayers. *Exhibit NSTAR-DOER 1-21* at iii-iv.

Massachusetts has expressed a clear preference that distributed generation be part of the evolving Massachusetts energy sector. Therefore, it is imperative that the Department take care to follow through on its expressed commitment to distributed generation and implement the recommendations of the Governor's Climate Protection Plan as well as the recommendations in the Report of the Governor's Task Force on Electric Reliability and Outage Preparedness.

In the present case, this means ensuring that standby rates are fair and reasonable in law, policy and fact. This does not mean that other ratepayers should cross-subsidize distributed generation. What it means is that if NSTAR Electric proposes rates that are not supported in fact, law and policy, then the Department should reject any such proposal and order standby rates that are fair and reasonable and that account for the benefits offered by distributed generation as well as the costs.

We agree with the Department that, "[I]deally, standby or backup service tariffs should ensure that customers pay an appropriate share of distribution system costs. When determining these costs, it is important to provide an appropriate price signal to customers seeking to install distributed generation."[6] We stress that a precondition to the attainment of each of these goals is accurate and sufficient data regarding costs, savings, usage, load and other data to support the assumptions underlying the proper design of standby rates. Equally important, the benefits of distributed generation must be considered and taken into account in order to meet the goals stated above.

Given that DG presents a potential competitive threat to the monopoly utility distribution companies, the Department should be vigilant in protecting the market from policies that by intent or effect improperly discourage competition. DG proponents are at a significant disadvantage in regulatory proceedings due largely to the fact that the monopoly distribution companies can rely on ratepayers to fund their regulatory activities. DG companies can ill-afford the substantial resources necessary to protect their interests in the regulatory arena. We therefore urge the Department to act decisively when faced with distribution company actions that are not fair or reasonable or supported by actual facts.

C. <u>Procedural History</u>

NStar Electric filed originally its proposed standby rates with the supporting testimony of Henry LaMontagne on October 31, 2003. On October 26, 2003, the

[6] *Order Opening Investigation Into Distributed Generation*, D.T.E. 02-38 at 4 (June 13, 2002).

Department suspended the operation of the tariffs until June 1, 2004. On January 16, 2004, NStar Electric refiled the tariffs. On January 29, 2004, the Department suspended the operation of the tariffs until August 1, 2004 in order to investigate the propriety of the Companies' proposed tariffs. The proceeding was docketed as D.T.E. 03-121 and William Stevens was designated the Hearing Officer.

On January 20, 2004, the Department issued a Notice of Public Hearing and Procedural Conference. The Notice states that the Department will investigate the proposed tariffs to ensure that NStar Electric used an appropriate method for the calculation of standby rates for customers with onsite generation facilities. The Notice further provides:

> In particular, the Department will investigate among other things, whether: (1) the proposed standby rates insure that customers with their own on-site self-generation facilities pay an appropriate share of distribution system costs; (2) distribution companies should recover their costs through fixed or variable charges; (3) standby rates should reflect embedded and/or incremental costs; and (4) distribution companies should offer firm and non-firm standby service.

NStar Electric, D.T.E. 03-121 (January 20, 2004)(Notice of Public Hearing and Procedural Conference).

On February 10, 2004, the Department conducted a public hearing and procedural conference. The Attorney General intervened pursuant to G. L. c. 12 § 11E. The Department granted full intervenor status to the following entities: Associated Industries of Massachusetts; the Boston Public Schools; Co-Energy America, Inc.; the Conservation Law Foundation, Inc. ("CLF"); the Division of Energy Resources ("DOER"); FuelCell Energy, Inc.; Fitchburg Gas and Electric Light Company ("FG&E"); Low Income Weatherization and Fuel Assistance Network and Mass. Community Action Program

Directors Association; Massachusetts Electric Company ("MECO"); National Association of Energy Service Companies, Inc.; the NE DG Coalition; the Solar Energy Business Association of New England ("SEBANE"); Siemens Building Technologies, District One; TEC; UTC Power, LLC; Western Massachusetts Electric Company ("WMECO"); and the Western Massachusetts Industrial Customer Group. The Department also granted limited participant status to the following entities: Allied Utility Network, LLC; The E-Cubed Company, LLC; Dgsolutions, LLC; Energy Concepts Engineering, PC; Keyspan Energy Delivery of New England; Pace Law School Energy Project; Power Plug, Inc.; Predicate, LLC; Wyeth Pharmaceutical, Inc.; and Constellation NewEnergy, Inc.[7] *NStar Electric, D.T.E. 03-121* (March 22, 2004)(Hearing Officer Ruling to Extend Time for Discovery of Intervenor Direct Cases).

On February 12, 2004, the NEDGC filed a Motion to Dismiss NStar Electric's January 16, 2004 filing. The NEDGC argued that the proposed rates violate the legal standards for standby rates established in *Cambridge Electric Light Company and Massachusetts Institute of Technology*, D.P.U./D.T.E. 94-101/95-36 (1995) ("*Cambridge*"); the Department's regulations at 220 C.M.R. 8.06; and regulations promulgated by the Federal Energy Regulatory Commission ("FERC") pursuant to the Public Utility Regulatory Policy Act ("PURPA") at 16 C.F.R. § 292.305. On February 24, 2004, the Companies filed an Opposition to the Motion to Dismiss. The motion remains pending before the Department.

[7] The following entities refer to themselves as the Joint Supporters: Allied Utility Network, LLC; the Boston Public Schools; Co-Energy America, Inc.; The E-Cubed Company, LLC; Dgsolutions, LLC; Energy Concepts Engineering, PC; National Association of Energy Service Companies, Inc.; Pace Law School Energy Project; Predicate, LLC; and Siemens Building Technologies, District One.

Nine intervenors filed pre-filed direct testimony with the Department. The NEDGC submitted the pre-filed direct testimony of Sean Casten of Turbosteam Corporation, Thomas W. Smith of Equity Office Properties Trust, Inc. and Spiro Vardakas of Aegis Energy Services, Inc. The TEC submitted the testimony of consultant Elaine Saunders. The DOER submitted the testimony of Alvaro E. Pereira. FG&E submitted the testimony of David K. Foote. WMECO submitted the testimony of Edward A. Davis. MECO submitted the testimony of Carlos A. Gavilondo. The Joint Supporters, CLF and DOER submitted the testimony of Mark B. Lively. The Joint Supporters also submitted the pre-filed testimony of Dave Hannus. SEBANE submitted the testimony of Andrew G. Greene. SEBANE and CLF submitted the testimony of Thomas S. Michelman.

On April 21, 2004, NStar Electric filed rebuttal testimony of three witnesses: Henry LaMontagne, Charles Salamone and Hethie Parmesano. The rebuttal testimony of LaMontagne included new proposed standby rates identified as Attachment NStar-HCL-10. At a procedural hearing on April 22, 2004, the NEDGC, the DOER and the Joint Supporters all registered objections to the introduction of new rates in the case immediately preceding the commencement of hearings. Also, over the objections of NStar Electric, the intervenors sought and were granted until April 26, 2004 to file discovery requests on the Companies' rebuttal testimony. NStar Electric was directed but failed to produce responses to all discovery by May 3, 2004.

On April 24, 2004, the NEDGC, the DOER, the Joint Supporters and CLF moved the Department to dismiss NStar Electric's case and to commence a new case based on the new standby rates identified as Attachment NStar-HCL-10. In the alternative, the moving parties requested that the Department disallow certain rebuttal testimony and modify the procedural schedule. This motion also remains pending before the Department.

The Department conducted eight days of evidentiary hearings commencing on April 28, 2004 and ending on May 13, 2004. The record consists of 614 exhibits, 42 record responses and 1,575 pages of testimony from fifteen witnesses.

ARGUMENT

I. THE DEPARTMENT SHOULD REJECT THE RATES AS PROPOSED AND RULE THAT DG CUSTOMERS BE OFFERRED FIRM SERVICE UNDER THE OTHERWISE APPLICABLE RATE SCHEDULES

The Department should reject the standby rates as proposed by NSTAR Electric and order the Companies to continue to offer to provide service to DG customers under the otherwise applicable rate schedules. The Department should rule that it is appropriate to provide DG customers service under the otherwise applicable rate schedules absent a cost of service study for standby customers.

A. The Proposed Rates Are Unduly Discriminatory.

1. It Is Unduly Discriminatory To Treat Customers With Similar Load Characteristics Differently.

NSTAR Electric has an exclusive franchise to provide delivery service within its service territories. G.L. c. 164, § 1B. *7 Tr. 1261.* A customer desiring delivery service within NSTAR Electric's service territories has no alternative to taking service from the Companies. *Id.* This includes customers with on-site generation. For its part, NSTAR Electric has an obligation to serve all customers, including customers with on-site generation. *G. L. c. 164, §1B. 7 Tr. 1261-1262.* Moreover, NStar Electric may not charge customers with onsite generation a higher rate than other customers unless the cost or conditions presented in supplying service are different.[8] *See e.g. Souther v. City of Gloucester,* 187 Mass. 552, 556 (1905) (special cost of serving outlying customers greater); *Brand v. Water Commissioners of Billerica,* 242 Mass. 223, 226 (1922) (supply

[8] The Companies' witness repeatedly testified that the Companies believe the cost of providing service to customers with onsite generation is the same as the cost of providing service to all requirements customers. *1 Tr. 47, 82, 85, 89, 143, 145.*

to track of summer cottages through single meter); *Ladd v. City of Boston,* 170 Mass. 332, 336 (1898) (unmetered service); *Flatley v. City of Malden,* 40 Mass. App. Ct. 38, 40-41 (1996) (master metered apartment complex). Customers with onsite generation have a legal right to nondiscriminatory treatment. *Weld v. Gas & Electric Light Commissioners,* 197 Mass. 556, 557 (1908); *Massachusetts Municipal Wholesale Electric Company v. City of Springfield,* 49 Mass. App. Ct. 108, 112 (2000). The Department has held that to "treat customers [with on-site generation] who have the similar loads differently is [unduly] discriminatory." *Boston Edison Company,* D.P.U./D.T.E. 85-266-A/85-271-A, p. 275 (1986).

The Department has long held that the availability and applicability of rate schedules must be based on objectives factors such as voltage level and the size and pattern of load. *Boston Edison Company,* D.P.U./D.T.E. 1720, p. 137-139 (1984); *Boston Edison Company,* D.P.U./D.T.E. 85-266-A/85-271-A at 273-276 and cases cited. To this end, the Department abolished rate class distinctions based on the nature of a customer's end use of electricity. For example, the Department eliminated special rates for water heating, space heating, churches, schools, apartment buildings and miscellaneous end uses. See *Boston Edison Company,* D.P.U./D.T.E. 85-266-A/85-271-A at 239-241, 256-265. Differences among customers that are not related to load are irrelevant in determining whether a customer should be served under a special rate. *Boston Edison Company,* D.P.U./D.T.E. 1720 at 139-140.

Regulations issued under the PURPA expressly prohibit discrimination against customers with Qualifying Facilities in comparison to rates for other customers. 18 C.F.R. §292.305(a)(1)(ii). Regulation 18 C.F.R. §292.305(a)(2) provides:

> Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's customers with similar load or other cost-related characteristics.

Under this regulation, a utility may not charge one rate to Qualifying Facilities and another rate to customers with similar load characteristics. This is consistent with the Department's precedent requiring the same rate for customers with similar load characteristics. Thus, in *Cambridge*, D.P.U./D.T.E. 94-101/95-36 at 47-48 the Department rejected the Company's proposal to charge customers with on-site generation on the basis of a contract demand instead of actual demand in the absence of specific load data demonstrating load characteristics different from those of other general service customers[9].

In *Boston Edison Company,* D.P.U./D.T.E. 85-266-A/85-271-A at 271-276, the Company proposed an auxiliary rate for customers with on-site generation. The Company contended that customers with on-site generation are distinguishable from most general service customers by their load shape. *Id*. at 274. However, the Company failed to demonstrate that the load characteristics of customers with on-site generation are, in fact, uniquely different from those of regular general service customers. *Id*. at 273. The Department rejected the Company's proposal to establish a separate rate for on-site generation customers, finding that the Company served customers with similar load characteristics under its general service rates. The Department held that to treat customers with on-site generation differently would be unduly discriminatory. *Id*. at 275.

2. The Testimony of Ms. Saunders and Mr. LaMontagne Establishes That The Load Characteristics Of Customers With

[9] For further discussion of the interaction of the proposed rates with the requirements of PURPA and related federal and state regulation, *see* Section III.B. below.

Onsite Generation Are Similar To Customers Without Onsite Generation.

The Companies' entire case is based on a false premise, i.e., that the load characteristics of customers with onsite generation ("DG customers") are substantially different from customers without onsite generation ("all requirements customers"). The Companies witness LaMontagne characterizes the demand of DG customers as "intermittent" and "infrequent". *Exhibit NStar-HCL-1* at 16, 17*; Exhibit NStar-HCL-7* at 4, 13, 14*; 1 Tr. 107, 168, 170.* Based on this assumed intermittent and infrequent use, NStar Electric asserts that the normal as-used demand and energy charges do not provide sufficient revenues to cover the costs of providing service. Thus, the essence of the Companies' case (and the basis for claiming that contract demand is appropriate for DG customers) is the bare unsupport6ed assumption that the load characteristics of DG customers are different from the load characteristics of all requirements customers. *1 Tr. 107; 2 Tr. 311-312.*

In designing the proposed standby rates, NStar Electric did not perform any kind of analysis or study which compared the load characteristics of DG customers on the NStar Electric system with the load characteristics of the all requirements customers on the NStar Electric system. *2 Tr. 282.* The premise that the load characteristics of DG customers are different is a naked assumption. The Companies provided no quantitative or qualitative analysis in support of this assumption. While the naked assumption is often repeated by Mr. LaMontagne (see references above) and Ms. Parmesano (Exhibit NSTAR-HSP-1 at 9), the fact of its repetition does not make it any more true.

As Ms. Saunders explained in her testimony, if the demands of DG customers were intermittent or infrequent as the Companies assume, then the load profiles of DG customers would be spiked or radically vary from month to month depending on the availability of their onsite generation. *Exhibit TEC-1* at 3. Ms. Saunders prepared an analysis which compares the load characteristics of DG customers to those of other customers on Rates G3, T2 and G2. *Exhibit DTE-TEC 1-2.* Her analysis compares the ratio of a customer's smallest billing demand to the largest billing demand. *Exhibit TEC-1* at 4, 5*; Exhibit DTE-TEC 1-2.* Customers with a low ratio have great variation in the demands they impose on the distribution system across the year. *Exhibit TEC-1* at 4. Customers with a high ratio incur roughly the same demand from month to month. *Id.*

Ms. Saunders's analysis shows that there is wide variation in usage patterns for all customers. The minimum to maximum ratio for customers on Rates G3, T2 and G2 spans the full spectrum from less than 10% to greater than 90%. Thus, there are many all requirements customers in NStar Electric's service territories who could be described as having "intermittent" loads. *Id.* Exhibit DTE-TEC 1-2 also shows the same information for customers with onsite generation. Again, the minimum to maximum ratio spans the full gamut and does not result in loads that are unusually spiked for the utility. There are plenty of other customers on the system with similar load characteristics at every level. *Id.*

Ms. Saunders performed a similar analysis using data obtained from MECO in 1999. *Exhibit TEC-1* at 4, 5. The results of her analysis of MECO are similar to those obtained for NStar Electric. MECO's all requirements customers show similar variation to customers with onsite generation.

In his rebuttal testimony, NStar Electric's LaMontagne criticized Ms. Saunders's use of the minimum to maximum billing demand ratio for comparing patterns between

DG and all requirements customers. *Exhibit NStar-HCL-7* at 13*; 7 Tr. 1201*. He states that her method is an inappropriate measure for "determining intermittence" when comparing DG and non-DG customers. *Exhibit NSTAR-HCL-7 at 13*. He asserted that a more accurate measure to compare billing demand patterns is the ratio of average billing demand to maximum billing demand. *Id.* at 14*; 7 Tr. 1201*. LaMontagne prepared frequency histograms of customers on Rates G-3, T-2 and G-2 using the average to maximum ratio and appended those histograms to his rebuttal testimony as Exhibit NSTAR-HCL-8. *7 Tr. 1201*. According to LaMontagne, these histograms indicate that there are very few customers with billing ratios at the low end of the spectrum of values. *Exhibit NSTAR-HCL-7* at 14, 15. He testified that it would be reasonable to expect a frequency histogram of DG customers to be concentrated at the low end of the average to maximum billing ratio chart. *Id.* at 15. He did not, however, provide a histogram chart for DG customers verifying his expectation.

In response to an information request propounded by TEC, LaMontagne prepared a histogram using his preferred average to maximum ratio for DG customers on the NStar Electric system. *Exhibit TEC 3-5; 7 Tr. 1203*. A comparison of Exhibit NStar-HCL-8 with Exhibit TEC 3-5 shows that even using LaMontagne's preferred method, DG customers exhibit similar load characteristics to those of all requirements customers.

LaMontagne testified based on Exhibit NStar-HCL-8 that the normal variability of medium and large industrial and commercial customers is in the range of 70% to 90%. *7 Tr. 1201*. These customers correspond to the 0.7, 0.8 and 0.9 deciles shown on NStar-HCL-8. *7 Tr. 1201-1202*. LaMontagne further testified that customers in the 1.0 decile exhibit somewhat less variation than customers in the 0.7 – 0.9 range and that customers in the 0.6 decile exhibit somewhat greater variation than the customers in the 0.7 – 0.9 range. *7 Tr. 1202.* Most DG customers are currently served under Boston Edison's Rate T-2. *Exhibit TEC 3-5.* The histogram for those customers shows that 76% of Rate T-2 customers are included in the 0.7 – 0.9 range and 96% of Rate T-2 customers fall in the 0.6 – 1.0 range. *7 Tr. 1202.*

The frequency histogram of DG customers shown on Exhibit TEC 3-5 shows the same load characteristics for DG customers. All but one of the customers fall in the 0.6 – 1.0 range. There is one customer in the 0.3 decile, but the variability in that customer's load is due to its internal load requirements and not the fact that the customer has onsite generation. *7 Tr. 1203-1206.*[10] Exhibit TEC 3-5 shows that, contrary to LaMontagne's rebuttal testimony, DG customers, like all requirements customers, exhibit load characteristics in the upper end of the frequency histogram, not the low end as he expected.

Based on the testimony of Ms. Saunders and Mr. LaMontagne, it is clear that DG customers have load characteristics similar to those of all requirements customers. Because the load characteristics are the same, the Department must reject NStar Electric's proposed standby rates and require that NStar Electric continue to serve DG customers under the otherwise applicable rate schedules. To treat DG customers otherwise, would be unduly discriminatory. *Boston Edison Company, D.P.U./D.T.E. 85-266-A/85-271-A* at 275[11].

[10] LaMontagne pointed out on redirect examination that the 0.3 decile outlier would not qualify for the Companies' proposed standby rates in any event. *8 Tr. 1568-1570.*

[11] The failure of NSTAR Electric to demonstrate that customers of a given class with DG have different load characteristics than customers in the class without DG also contravenes Massachusetts regulations applicable to Qualifying Facilities, the federal PURPA law and the applicable federal regulations. These laws and regulations are discussed in further detail in Section III.B below.

B. <u>The Proposed Rates Violate The Department's Rate Structure Goals.</u>

Mr. LaMontagne testified that the Department's longstanding rate structure goals of fairness and economic efficiency are applicable to the proposed NStar Electric rates. *Exhibit NStar-HCL-1*at 11, 12*; 1 Tr. 124, 125.* Fairness means that the rate structure should require that no class pay more than the cost of serving that class. E.g. *Boston Edison Company,* D.P.U./D.T.E 1720, at 112-113. *1 Tr. 124.* Economic efficiency means that rates should reflect the cost of service and provide an accurate basis for customer's decisions about how to fulfill their needs. *D.P.U./D.T.E 1720* at 112. *1 Tr. 125.*

Mr. LaMontagne further testified that the Department's goals of fairness and economic efficiency effectively circumscribe the policy goals for standby rates identified by the Department in *Order Opening Investigation into Distributed Generation,* D.T.E 02-38, at 4, June 13, 2002. *Exhibit NStar-HCL-1* at 10, 11*; 1 Tr. 134-138.* In D.T.E. 02-38, the Department identified the following policy goals for standby rates:

> Ideally standby or backup service tariffs should ensure that customers pay an appropriate share of distribution system costs. When determining these costs, it is important to provide an appropriate price signal to customers seeking to install distributed generation. Backup rates that are too high may inappropriately discourage the development of distributed generation. However, backup rates that are below the actual cost of providing service could shift these costs to other customers.

D.T.E. 02-38, at 4.

Mr. LaMontagne testified that these goals are effectively restatements of the traditional rate design goals of fairness and economic efficiency as applied to distributed generation. *1 Tr. 134-138.*

To promote its goals of fairness and economic efficiency, the Department engages in a two-step process: cost allocation and rate design. E.g. *Boston Edison Company,* D.P.U. 92-92, p. 16-17 (1992), *Boston Edison Company,* D.P.U. 1720 at 113. *1 Tr. 140.* The cost allocation step allocates a portion of the Companies' total costs to each rate class. The resulting allocation for each class represents the cost of serving that class, given the Companies' level of total costs. *D.P.U. 1720* at 113. *1 Tr. 142.* The cost allocation process or cost of service study ("COSS") is used as a basis of determining the costs each rate class should bear. *D.P.U. 1720* at 115. *1 Tr. 142.* The COSS approved by the Department represents the best estimate available to the Department of the cost of serving each rate class. *Id.* By setting rates equal to the revenue requirements indicated by the COSS, the Department achieves its goal of fairness. *D.P.U. 1720* at 114-115. *1 Tr. 143.* Both Ms. Parmesano and Mr. LaMontagne testified that a COSS "is required to identify the most accurate cost of providing any utility service." *Exhibit NSTAR-HSP-1* at 11. *1 Tr. 148.*

1. The Proposed Rates Are Inappropriately Based On The Otherwise Applicable Rates.

Despite the Department's longstanding practice and the admission of NStar Electric's witnesses that a COSS is the most appropriate basis for determining the costs that DG customers should bear, NStar Electric did not prepare a COSS for DG customers. *1 Tr. 143.* Instead, the proposed standby rates are based on the rate schedules applicable to all requirements customers *NStar-HCL-1* at 16. According to Mr. LaMontagne, the proposed standby rates are designed to recover the revenue requirements associated with all requirements customers. *2 Tr. 286.* In *Cambridge,* D.P.U./D.T.E. 94-101/95-36 at 46, the Department rejected standby rates based on rates applicable to all requirements customers because such rates are designed to recover the revenue requirements associated with the provision of all requirements service as opposed to standby service. In *Cambridge*, the Department further held that, in absence of any cost or load data specific to standby service (which data would enable the determination of a revenue requirement for standby customers), standby service rates should be based on marginal cost. *Id.* at 45-46.

Mr. LaMontagne and Ms. Parmesano asserted that rates for DG customers should be based on the otherwise applicable rate schedule. *Exhibit NSTAR-HCL-7* at7*; Exhibit NSTAR –HSP-1* at 9. Mr. LaMontagne stated that setting rates for DG customers on the basis of the otherwise applicable rates "promotes fairness and economic efficiency." *Exhibit NSTAR-HCL-7* at 7. Ms. Parmesano stated that rates for DG customers must be based on the otherwise applicable rates to "comply with the Department's policy on economic efficiency." *Exhibit NSTAR-HSP-1* at 9. They both asserted that pricing on the basis of the otherwise applicable rate schedule would result in customers making economically efficient decisions in deciding whether to install DG. *NSTAR-HCL-7* at 7*, NStar-HSP-1* at 9.

There is no basis in the record or Department precedent for these claims. The Department's fairness objective requires that no customer pay more than the cost of providing service. E.g. *Boston Edison Company,* D.P.U./D.T.E. 1720 at 112-113. *1 Tr. 124.* The Department's economic efficiency goal requires that rates be set at marginal cost. *Id.* at 118. *2 Tr. 201.* The record demonstrates that the otherwise applicable rates are roughly double both the embedded revenue requirement and the marginal cost of providing service. *2 Tr. 235-241, 244-246.*[12]

Clearly setting rates for DG customers based on the otherwise applicable rates violates both the fairness and economic efficiency objectives. DG customers would pay double the embedded and marginal cost of providing service. This would result in not only DG customers subsidizing other customers but also incorrect and inefficient decisions by customers about whether to install DG.[13]

As in *Cambridge,* the Department should reject NStar Electric's proposal to base standby rates on the rates applicable to its all requirements customers. NStar Electric cannot prove that its rates to all requirements customers are equal to the revenue requirements associated with the provision of service of standby customers. In fact, the evidence shows that they are not equal. Moreover, the Companies' proposal violates the Department's goals of fairness and economic efficiency and would lead to inefficient decision-making by customers considering DG.

2. The Otherwise Applicable Rates Do Not Reflect The Cost Of Providing Service to DG Customers.

The Companies current distribution demand charges are roughly twice the cost of providing services measured on both a marginal cost and embedded cost basis. Therefore, the Companies' proposal to base the proposed standby rates on the otherwise applicable rate schedules violates the Department's objectives of fairness and economic efficiency. Those objectives require that rates be set in accordance with marginal costs and embedded revenue requirements.

[12] *See* Section I. B. 2 *intra*.

[13] LaMontagne testified that the Department's goal of continuity has no application to this case because the proposed rates would apply only to new customers. *1 Tr. 125-127.*

a. Marginal Cost

Mr. LaMontagne and Ms. Saunders testified that Boston Edison's marginal distribution cost for Rates G-3, T-2 and G-2 could be calculated from the Companies' compliance filing in Docket D.P.U. 92-92. *Exhibit NEDGC 1-2(d)(Supp.).* The compliance filing shows that the marginal distribution cost of providing service to customers on Rates G2 and T2 is $8.96 in the summer and $5.71 in the winter. *NEDGC 1-2(d)(Supp.), p. 000057, line 19/line 8; Exhibit TEC 2-2; 2 Tr. 234-235.* They further stated that the marginal distribution cost for Rate G3 is $5.29 per kilowatt in the summer and $3.68 per kilowatt in the winter. *NEDGC 1-2(d)(Supp.), p. 000059, line 19/line 8; Exhibit TEC 2-2; 2 Tr. 243.* The following table compares the current distribution rates with the corresponding marginal distribution costs:

b. Comparison of Current Distribution Rates With Full Marginal Distribution Costs

Rate G-2	Summer	Winter
Marginal Cost/kW	$8.96	$5.71
Current Rate/kW	$20.22	$9.43
% of Cost	225%	165%

Rate T-2	Summer	Winter
Marginal Cost/kW	$8.96	$5.71
Current Rate/kW	$17.51	$8.18
% of Cost	195%	143%

Rate G-3	Summer	Winter
Marginal Cost/kW	$5.29	$3.68
Current Rate/kW	$11.66	$5.58
% of Cost	220%	192%

The table shows that the Companies' otherwise applicable rates are roughly twice the marginal cost of providing service. *2 Tr. 236-237, 244.*

c. Embedded revenue requirements

The otherwise applicable rates are also well in excess of the revenue requirements shown in the Companies' most recently approved COSS. For Rates G2 and T2, the marginal distribution revenue requirement from the Companies' compliance filing is approximately $114 million. *NEDGC 1-2(d)(Supp.), p. 000057, line 19; 2 Tr. 240.* In comparison, the embedded distribution cost revenue requirement from the Companies' most recently approved COSS is $118 million. *Exhibit D.T.E. 2-25, Schedule 20, p. 1-C, line 54; 2 Tr. 239.* For Rates T2 and G2, the embedded cost revenue requirement and the marginal cost revenue requirement are very close. *2 Tr. 240.* Consequently, the current distribution demand charge for Rates T2 and G2 are significantly higher than both the marginal cost and the embedded cost revenue requirement. *2 Tr. 240-241.*

For Rate G3, Mr. LaMontagne testified that the marginal distribution revenue requirement is about $29 million based on the Companies' compliance filing. *Exhibit NEDGC 1-2(d)(Supp.) p. 000059, line 19; 2 Tr. 240.* The embedded cost revenue requirement for Rate G3 is about $22 million. *Exhibit D.T.E. 2-25, Schedule 20, p. 1-C, line 54; 2 Tr. 245.* In the case of Rate G3, the marginal revenue requirement is higher than the embedded cost of providing service. *2 Tr. 245.* Accordingly, the Companies' current distribution charge for Rate G3 is higher than both the embedded cost and marginal cost of distribution.

Based on the testimony of Mr. LaMontagne using the otherwise applicable rate schedules to establish standby rates would plainly violate the Department's fairness and economic efficiency goals. The charges for distribution in the Companies' current rates are roughly twice the cost of providing service. The Department's fairness goal provides that no rate class should pay more than the cost of providing service as measured by the Companies' most recently approved COSS. Basing the proposed standby rates on the otherwise applicable rates would also violate the Department's economic efficiency goals. The Department has determined that economic efficiency is best satisfied by setting rates at marginal costs. Thus, in *Cambridge,* the Department held that, in absence of any cost or load data specific to standby service, standby rates should be based on marginal cost. *Cambridge at 45-46.* The evidence in this case is clear that the Companies' current distribution charges are roughly twice the marginal cost of providing service. Accordingly, basing the proposed standby rates on the otherwise applicable rates would violate the Department's goal of economic efficiency.

3. The Cost of Providing Service To DG Customers Is Less Than The Cost of Providing Service To All Requirements Customers.

a. Embedded costs

Mr. LaMontagne and Ms. Parmesano testified that the proper way to determine the revenue requirements for a class is a COSS. *1 Tr. 148; Exhibit NStar-HSP-1* at 11. In this case the Companies did not prepare a COSS for DG customers. *1 Tr. 143.* However, Mr. LaMontagne testified regarding how a COSS is performed.

A COSS is developed by adding up the operation and maintenance expense, depreciation, taxes and return on investment. These costs represent the costs to the Companies of owning and operating the various assets. *1 Tr. 152.* The COSS allocates these costs to the various rate classes. *1 Tr. 155.* The resulting allocation to each class forms the revenue requirement for that class. *1 Tr. 155.* Mr. LaMontagne testified that the allocation of most costs of providing service follows the way in which the plant accounts are allocated. *1 Tr. 157-158.*

In their last approved COSS, the Companies used a probability of dispatch ("POD") allocator to allocate transmission and distribution plant. *Exhibit NEDGC 4-9; 1 Tr. 159, 164.* The development of the POD allocator is a two-step process. First, costs are allocated to time periods based on the system load during the time period. Mr. LaMontagne testified that the POD allocator uses 256 allocation points representing typical weekday and weekend day loads for each month of the year. If the load is higher in a particular time period, the POD method allocates relatively more costs to that time period. *1 Tr. 159-161.* Second, the costs allocated to each time period are allocated to rate classes based on the class load as a percentage of the total system load during each time period. Rate classes that use transmission and distribution facilities during peak times are allocated relatively more costs than those that use the facilities off peak. *1 Tr. 161, 162, 170-171; 2 Tr. 189.*

All requirements customers tend to use transmission and distribution facilities during high load periods. Mr. Salamone testified that all requirements customers respond to extreme weather conditions and that this response gives rise to peak load conditions. *7 Tr. 1273*. Mr. LaMontagne concurred that peak load conditions are driven by summer temperatures and, in particular, air conditioning loads during the summer months when the temperatures are high. *2 Tr. 212.* Therefore, under the POD method, all requirements customers would tend to use a greater proportion of the system load during peak load times and would be allocated a proportionately greater share of the costs of transmission and distribution facilities.

In contrast, the standby demands of DG customers are not driven by weather. *2 Tr. 199.* The demand for standby service is generally driven by unforced outages and scheduled maintenance. Unforced outages can occur at any time. They are a random event and are not driven by weather. Scheduled maintenance can be planned to occur during times when system load is low. Because the standby demand of DG customers is not driven by weather, a DG rate class would likely be allocated less relative cost under the POD allocator than the all requirements class because the POD method assigns relatively more cost to peak loads than to off peak loads. *1 Tr. 161, 162, 166.*

Based on the foregoing, if the Companies were to perform a COSS which included DG customers as a separate rate class, the revenue requirement for DG customers would be relatively less than the revenue requirements for the all requirements customers.

b. Marginal costs

A similar analysis pertains to the development of marginal cost revenue requirements. In the case of marginal costs, the individual class contributions to annual system peak are used to determine the marginal revenue requirement. *2 Tr. 211.* If a customer is on at the time of system peak that customer contributes to the marginal demands costs. If a customer is not on at time of system peak it would have no contribution to the marginal revenue requirements. *2 Tr. 211-212.* The system peak for Boston Edison tends to occur in June, July or August. *2 Tr. 212.* Based on Mr. Salamone's testimony, it is likely that most all requirements customers will demand service during the time of system peak. *7 Tr. 1272-1273.* However, as discussed above, that is not necessarily the case for DG customers. *2 Tr. 199.* Standby demands are driven by planned and unplanned outages of the DG facilities and not extreme weather conditions. Accordingly, if the Companies performed a marginal cost of service study, the marginal revenue requirement for DG customers would be less than the marginal revenue requirements of all requirements customers. Accordingly, it is inappropriate for the Companies to base their proposed standby rates on the otherwise applicable rate schedules.

4. The Companies' Planning Process Does Not Support The Proposed Rates.

NStar Electric claims that its generally applicable rates schedules are appropriate because "standby customers cause costs to be incurred in the same manner as comparable nonstandby customers". According to NStar Electric's witness, "the Companies must plan for, build and have available distribution and transmission facilities needed to meet the full demand of the [DG] customer". *Exhibit NSTAR-HCL-1* at 16.

The sole basis for the Companies' assertion that the cost of providing service to standby customers is the same as the cost of providing service to all requirements customers is the testimony of Mr. Salamone regarding the Companies' planning process. *2 Tr. 289.* The Companies rely exclusively on Mr. Salamone's testimony. *2 Tr. 290.* The Companies have no basis, other than Mr. Salamone's testimony, for claiming that the cost of providing standby service is the same as providing service to all requirements customers. *1 Tr. 147-149.*

Mr. Salamone's testimony regarding the Companies' planning process belies the Companies' assertion that the cost of providing service to standby customers is the same as providing service to all requirements customers. Mr. Salamone testified that the Companies plan distribution facilities by forecasting the peak load on distribution circuits and substations over a five to ten year horizon and planning facilities to meet that forecasted load. *7 Tr. 1273, 1283.* The forecast of the peak load begins with the existing load which is measured for each distribution circuit and substation. *Exhibit NSTAR-CPS-1* at 4, 6. The Companies then add projected peak load additions to the existing peak load. Peak load additions are projected on the basis of an econometric forecast. *Id.* at 5. The Companies also add in known load increases above one megawatt. *Id.* The projected peak loads are adjusted to reflect extreme weather conditions. *7 Tr. 1274.* According to Mr. Salamone "extreme weather conditions invariably lead to peak load conditions". *Exhibit NSTAR-CPS-1* at 5. For the NStar Companies the peak load occurs in the summertime. *7 Tr. 1271.* Accordingly, the Companies' peak load forecast is adjusted to reflect extreme summer weather conditions. *7 Tr. 1272.*

There is nothing in the Companies' planning process that supports the assertion that the Companies' plan distribution facilities to meet the standby demands of DG customers or that the cost of serving DG customers is the same as the cost of serving all requirements customers. For planning purposes, the Companies assume that all DG customers were all requirements customers prior to the installation of onsite generation. *7 Tr. 1284.* Thus if an existing customer installs distributed generation, the NStar system already has sufficient capacity in place to supply that customer's full requirements even with the customer's generator out of service. *Id.* The facilities necessary to serve the peak load requirements of DG customers would already have been installed and therefore the installation of a DG facility does not require NStar Electric to install any additional facilities. *7 Tr. 1284-1285.*

Thus, the Companies' planning process does not result in the Companies installing facilities to serve customers who install DG facilities. Any demand associated with DG facilities would be captured in the Companies' existing peak since that peak necessarily includes the load of DG customers prior to the installation of DG facilities. Moreover, to the extent onsite generation is operating at the time of peak load, it reduces the existing demand on the distribution system and would be reflected in the existing peak load from which the Companies build the load forecast. *7 Tr. 1285.*

Mr. LaMontagne testified that the Companies' distribution planners assume that customer onsite generation will be out of service at the time of the distribution system peak. *1 Tr. 115, 117.* Even if that were the case, it would not necessitate additional investment in distribution capacity because the Companies assume that the DG customers were all requirements customers prior to the installation of self-generation and therefore, the system already has sufficient capacity to supply that customer's full requirements even with its generator out of service. *7 Tr. 1284.* To the extent that onsite generation is operating at the time of peak load conditions, that generation would have the effect of reducing the measured peak at the Companies' substations and distribution circuits and lower the Companies' forecast of peak load conditions.

Based on the foregoing, NStar Electric does not explicitly track or take into account the installation of distributed generation in its distribution planning process. Moreover, to the extent that DG reduces demand at time of system, that reduction is recognized implicitly in the Companies' peak load forecast because the peak load forecast is based on the measured demand of the Companies' substations and distribution circuits.

Based on the foregoing, the testimony of LaMontagne and Salamone does not support the Companies' assertion that the cost of serving DG customers is the same as the cost of supplying all requirements customers.

5. The Proposed Rates Contain A Prohibited Demand Ratchet.

NStar Electric's proposed standby rates assess charges on the basis of a contract demand, as opposed to actual demand. *Exhibit NSTAR-HCL-1* at 18. In *Cambridge*, the Department rejected contract demand as the basis for standby rate charges. *Cambridge* at 47-48. Charges based on a contract demand constitute a demand ratchet. *Id.* at 47. The Department has a longstanding precedent against demand ratchets because "they distort incentives to conserve and could unfairly impose higher costs on certain customers". *Id.* at 47*, citing Massachusetts Electric Company,* D.P.U./D.T.E. 92-78, p. 188 (1992); *Western Massachusetts Electric Company,* D.P.U./D.T.E. 86-280, p. 196 (1987); *Western Massachusetts Electric Company,* D.P.U./D.T.E. 84-25, p. 199 (1984).

In addition, the Companies have failed to support their assumption that all distributed generation will be out of service at the time of system peak. This contravenes the PURPA requirements for sales of standby power to Qualifying Facilities. Regulation 18 C.F.R. 292.305(c) provides that standby rates:

> shall not be based upon an assumption (*unless supported by factual data*) that forced outages or other reductions in electric output by all Qualifying Facilities on electric utility system will occur simultaneously, or during a system peak, or both; [emphasis supplied.]

Here, NSTAR Electric has not provided any factual data supporting its assumptions that all distributed generation will be out of service at time of system peak. Mr. Salamone did not present any load data regarding standby customers in his testimony. *2 Tr. 289-290.* He offered several reasons why an onsite generation facility may be out of service, such as unplanned or maintenance outages. *NSTAR-CPS-1* at 8. He testified that DG facilities may be shut down as a result of "high fuel prices, the opportunity to pursue fuel arbitrage options, maintenance scheduling and the unavailability of facility personnel". *Id.* at 9. However, on cross-examination, Mr. Salamone was unable to explain how any of these stated reasons related to peak load conditions, which are caused by extreme weather. *7 Tr. 1274-1280.* Mr. LaMontagne agreed that while the loads of all requirements customers are driven by weather and business routines, it is not necessarily true that DG customers will require standby service at the same time that other customers are using the facilities. *2 Tr. 199.*

The Department further held that in absence of standby class specific load data, there is no evidence that assessing standby charges on the basis of actual demand would cause under recovery of costs. *Cambridge* at 47-48. The Department held that, in fact, the use of contract demand is likely to cause over-recovery of distribution costs because unless the customer has exactly the same demand every month, the total billing demand will be less than twelve times the maximum monthly billing demand. *Id.* Accordingly, the Department denied the use of contract demand for standby rates and directed the use of actual monthly demand. *Id.*

NStar Electric has not offered a scintilla of evidence that would cause the Department to depart from its holding in *Cambridge* or its longstanding precedent against precedent against demand ratchets. NStar Electric offers no load data for standby rate customers in support of the proposed rates. Rather, NStar Electric uses a load data for its all requirements customers to design the proposed standby rates. *Exhibit NSTAR-HCL-1* at 24-25. Mr. LaMontagne testified that he does not even know whether the proposed rates will yield more or less revenue than the otherwise applicable rates. *7 Tr. 1188-1190.* We note this testimony from the Hearing is implicitly contradicted by his prior direct testimony where he states that DG customers who take interruptible service under the otherwise applicable rates will be charged a "lower price" than those who take firm standby as proposed. *Exhibit NSTAR – HCL – 1 at 26.*

NSTAR Electric has failed to support its proposed standby rates based on contract demand. Accordingly, the Department should reject NStar Electric's filing and order that customers with onsite generation continue to be offered service under the otherwise applicable rate.

C. The Proposed Rates Are Anticompetitive and Will Discourage New Distributed Generation In NSTAR Electric's Service Territory

The undisputed evidence presented in this case demonstrates that the proposed rates will discourage the deployment of distributed generation in NSTAR Electric's service territory. The undisputed evidence further shows that the negative impact will be most pronounced in Boston Edison's territory. Thus, by intent or effect, the NSTAR Electric's proposed standby rates will discourage or exclude DG from NSTAR Electric's service territory and will thus limit competition. As a result, Massachusetts customers will be prevented from fully realizing the benefits that distributed generation can bring to energy consumers. The evidence in this case suggests that NSTAR intends this anti-competitive effect.

In addition, by inappropriately precluding DG, the proposed rates will deprive Massachusetts citizens and businesses the benefits that DG can offer – both to the electric distribution system and to the society at large. While the parties may disagree about the scope and extent of benefits of DG and argue about how and whether such benefits should be accounted for in the rates applicable to customers who install DG, it is not disputable that if deployment of distributed generation is precluded, then the benefits of DG will not be realized. These outcomes run directly counter to the stated policies of the Commonwealth of Massachusetts.

The testimony of the only witnesses in the case with any significant experience in the design, construction, operation and ownership of distributed generation systems[14] makes clear that the proposed NSTAR Electric Standby Rates will have the following anticompetitive impacts on distributed generation.

The testimony shows that NSTAR Electric's proposed rates will impose higher costs on customers with DG than they would pay under the otherwise applicable rates. Mr. Casten of Turbosteam Corporation, a provider of very clean, highly efficient co-generation systems, testified that the rates as proposed by NSTAR Electric would increase the costs of standby service by between 15% and 50% over the otherwise applicable rates. *Exhibit NEDGC-1* at 6. In addition his analysis shows that under certain common operating assumptions, particularly for renewable DG, the additional costs imposed by the new rates could totally outweigh any energy savings from the DG literally making the customer pay more to NSTAR Electric for not taking service, than they would have paid without the DG system in place. *Exhibit NSTAR-NEDGC 1-12*.

[14] Not one of the NSTAR witnesses has any significant experience in the design, ownership, or operation of DG.

He further stated that if the rates are imposed, his company would not continue to do business in NSTAR Electric's territory. Id. Upon cross-examination, Mr. Casten testified that in his view, the proposed standby rates would "be disastrous" for DG. *3 Tr.* at 415.

Mr. Smith of Equity Office Properties, the largest commercial property owner in Boston with an active national DG program, testified that that if the proposed rates are adopted, that there is no question the NSTAR Electric standby rates will raise the cost of obtaining standby service for customers seeking to install distributed generation. *Exhibit NEDGC-3 at 6*. Moreover, if the rates are approved, Equity Office Properties will likely not install any distributed generation in its Boston properties for the foreseeable future. *Exhibit NEDGC-3 at 6*. Mr. Smith further testified that the proposed contract demand based standby charges will "discourage others from pursuing cost effective CHP (combined heat and power) projects in NSTAR Electric's service territory. *Exhibit NEDGC-3* at 12-13.

Mr. Vardakas of Aegis Energy Services, a provider of DG equipment to mid-size institutional customers, testified that the proposed rates would likely have a "significantly negative impact on [his] business" of selling, installing and monitoring DG systems to medium-size institutional customers. *Exhibit NEDGC-2* at 6. Between the additional charges and the complexities of the rate," he believes his customers will be deterred from purchasing a combined heat and power system. *Exhibit NEDGC-2* at 6.

Mr. Hannus of Co. Gen America, a distributor of cogeneration equipment, testified that the rate proposal has required him to put on hold two projects within the

Boston public schools because the economic impact of the proposed rates renders the projects financially unviable. *Exhibit JS-DH-1* at 4.

Second, the rates are complex in design and difficult to understand and administer. This complexity will increase the cost of operations and deter customers from installing distributed generation. Mr. Vardakas' direct testimony demonstrates that smaller scale customers of the type that install his systems frequently do not understand their energy bills. *Exhibit NEDGC – 2 at 6.* These customers do not have the sophistication or the resources to ensure invoice accuracy that DG investments depend on. *Id.* This concern is real as evidenced by the fact that in response to an NSTAR information request, Mr. Vardakas produced 14 examples of NSTAR providing inaccurate billing to customers with distributed generation. *See NEDGC 1-26 and 1-27.*

Third, the notice periods in the proposed rates would have a negative impact on customers due to the long lead times. Mr. Smith specifically testified that the 3 year period that the Company proposed for requiring a customer to provide prior written notice of intent to switch to "non-firm" service was onerous and would deter his company from seeking that option. *Exhibit NEDGC-3* at 10. On cross-examination, Mr. LaMontagne was asked to explain how this notice was required to ensure a "reasonable level" of cost recovery. *3 Tr.* at 401. His response was indicative of the Company's approach to distributed generation and highlights the strained factual assumptions underlying the Company's rate design in this case. Mr. LaMontagne stated that the Company performed no formal study "per se" to come up with the 3 year term, rather it just "seemed" like a reasonable period of time for which potential load growth would take up the capacity that was released by the firm customer who decides to go to non-firm status. *3 TR.* at 401-403. He goes on to state that the 3 year wait will prevent a customer from gaming the system, by applying for firm service, "the infrastructure is put in place to serve that customer on a firm basis, and then the customer determines to go to non-firm service." 3 *TR* at 403. The fallacy of this argument is the premise that the Company is installing capacity to serve the standby load of a customer installing DG. In the vast majority of cases, DG is installed on existing lines. Mr. Vardakas testified that 95% of his systems go on existing lines. *Exhibit NEDGC-2* at 3. NSTAR Electric is not making any new investment in capacity to serve the DG customer. Therefore, there is no rationale for requiring a 3 year waiting period, other than NSTAR Electric's desire to keep customers with DG from moving from firm to non-firm service. Similarly, the six-month notice required to cancel standby service is also unnecessary and onerous. The justification offered by Mr. LaMontagne was that the requirement was parallel with the existing requirements for otherwise applicable rates. *3 Tr. 404.* If the standby service is no longer requested, either the customer is no longer taking service, in which the otherwise applicable provisions would apply – and presumably so would the enforcement or lack thereof. If, the customer stays on as a customer of NSTAR, then they would likely be demanding additional capacity to replace the standby capacity they no longer need, and it seems onerous to require an ongoing customer to pay multiple times for the same capacity.

Fourth, Mr. Smith testified that in his experience, customers installing DG would not want the Company to have an absolute right to own metering equipment 'behind the fence" (past the Company's meter) on the distributed generation. Such a provision gives NSTAR the right to monitor performance of a customer and competitors internal use of electricity. To the extent that such metering is necessary for a customer to take advantage of a dispatchable load or other program on a voluntary basis, it is not objectionable.

The modifications and amendments proposed by NSTAR Electric in their amended rate filing,[15] will do very little to soften the harsh anti-competitive effect of these rates for the members of the NE DG Coalition. Even if the provisions from the standby tariff for Rochester Gas & Electric introduced into this proceeding by the Department[16] ("Rochester Provisions") were to be adopted, the fundamental problems and the anti-competitive impacts of NSTAR Electric's proposed Standby Rates would not be solved. As Mr. Casten put it, the Rochester provisions, save one, are akin to "putting lipstick on a donkey". *3 Tr. 415.* The opt-out exemption for renewable and efficient cogeneration technologies is a provision that should be adopted, or one like it that exempts DG that meets the requirements of Qualifying Facilities under Massachusetts law. See 220 CMR 8.02 for definition of Qualify Facilities.

Finally, the question of whether NSTAR Electric has anti-competitive intent is not one easily answered or proved. However, to the extent that NSTAR Electric believes that installation of distributed generation will lead to under-recovery of costs or lost revenues, then it would only be rational to expect them to act to limit such competition. And one could reasonably infer anticompetitive intent from the assumptions NSTAR Electric makes in the design of the proposed rates, the testimony of the witnesses and the other actions that NSTAR Electric has taken.

---

[15] As part of its rebuttal case, NSTAR filed new proposed rates that were not included as part of the original rate filing. We submit that such rate modifications should not be considered as part of this case. Particularly where they involve matters not previously in issue.

[16] On May __, the Department provided notice to all Intervenors that it intended to cross-examine witnesses regarding certain provisions of Service Class 14, under the Tariff of Rochester Gas & Electric Co [INSERT CITE]

NSTAR Electric produced several letters to customers who were considering the installation of distributed generation. *Exhibit NEDGC- 5-4 Supp.* These letters evidence a pattern of discouraging customers from installing distributed generation. In a letter dated September 8, 2003 from the President of NSTAR to the President of Boston University, NSTAR Electric stated:

> Even though these delivery facilities may only be used by BU on a "stand by" basis, NSTAR must build and maintain this capacity and keep it available for service at all time. As a result, the fuel cell will not produce any delivery network cost savings. *Exhibit NEDGC – 5-4.*

While NSTAR Electric might want to argue that they are merely informing a customer of future potential rate increases, the clear language suggests otherwise. If Boston University is served under Boston Edison's G3 or T2 rate then it appears NSTAR Electric may well be inaccurately characterizing the rates that Boston University would face as of the date of the letter and misinforming them that they will not receive any distribution savings from the DG installation. *Id.* The other letters provided evidence of disputes regarding interconnection matters, which reflect ongoing disagreements between NSTAR Electric and its customers regarding the terms of interconnection. *Id*[17].

As argued elsewhere in this brief, NSTAR Electric makes a series of assumptions regarding DG that support the proposed standby rate, while arguing against inclusion of any benefits in the rate design. Two quick examples illustrate the point. First, as discussed in Section I above, NSTAR makes the unsupported assumption that customers with DG have load characteristics that are "infrequent", intermittent or otherwise significantly distinct from other customers of the same class. NSTAR Electric's rate

[17] At the same time, NSTAR Electric proposed owning and operating its own distributed generation facilities. Exhibit NEDGC-NSTAR 2-4.

design also assumes that all DG will fail simultaneously, and at the time of system peak load. Second, though NSTAR Electric's witnesses concede that under certain conditions, that DG can provide benefits to NSTAR, NSTAR Electric nonetheless argues that future benefits from DG should not be factored in the rates because such benefits are not quantifiable or know today due to lack of DG deployment. Thus, NSTAR Electric assumes high future costs based on substantial DG penetration, but argues that future benefits that would correspond to such increases in DG deployment should not be included, even though NSTAR Electric has conceded that such benefits may exist in the future.

In conclusion, the undisputed testimony of the only witnesses in the case with actual experience designing, owning, operating distributed generation is that the rates will by intent or effect, discourage distributed generation in Massachusetts. This outcome runs counter to the stated policies of the Department and the Commonwealth of Massachusetts. Moreover, NSTAR Electric has the motive to deter distributed generation. And evidence in the case could support the inference that the motive has been acted upon in this case.

The modifications and amendments proposed by NSTAR Electric in their amended rate filing,[18] will do very little to soften the harsh anti-competitive effect of these rates. While the provisions from the standby tariff for Rochester Gas & Electric introduced into this proceeding by the Department[19] ("Rochester Provisions") could well

---

[18] As part of its rebuttal case, NSTAR filed new proposed rates that were not included as part of the original rate filing. We submit that such rate modifications should not be considered as part of this case, particularly where they involve matters not previously in issue.

[19] On April 20, 2004 the Department provided notice to all Intervenors that it intended to cross-examine witnesses regarding certain provisions of Service Class 14, under the Tariff of Rochester Gas & Electric Co. *NStar Electric, D.T.E. 03-121* (April 20, 2004)(Notice of Examination on Rochester Gas & Electric Company's Standby Service Tariff, Service Class No. 14.)

ameliorate some of the harsher aspects of the proposed rates for some customers, it is our contention that were the Rochester Provisions to be adopted, the fundamental problems and the anti-competitive impacts of NSTAR Electric's proposed Standby Rates would not be solved.

II. THE DEPARTMENT SHOULD REQUIRE THAT STANDBY SERVICE BE OFFERED AS AN OPTIONAL SERVICE AND MODIFY THE PROPOSED STANDBY RATES.

The Department should require that the new standby rates be offered as an optional service and modify the proposed standby rates as discussed below. In the alternative, even if the Department elects to approve new standby rates as an exclusive service for customers with DG, it is even more imperative to incorporate the modifications listed below. The modification suggested in Section III A. below regarding Qualifying Facilities is necessary to avoid a direct conflict with existing Massachusetts regulations and federal law and regulations.

A. The Proposed Rate Should Contain An Exemption For Qualifying Facilities

The proposed rates should contain an exemption for "Qualifying Facilities," as the term is defined in 220 CMR 8.02.[20] As proposed, the rates conflict with the Departments existing regulations applicable to Qualifying Facilities. The rates also conflict with the requirements of PURPA and the applicable federal regulations.

An exemption for Qualifying Facilities is consistent with other Massachusetts rulings affecting DG, in particular the recently adopted Model Interconnection Standards that were developed and recently approved by the Department. *See Order 02-38-B issued February 24, 2004.* In addition, California and other states that have recently adopted new guidelines for standby rates include exemptions or exclusions for Qualifying Facilities or the DG technologies that typically satisfy the criteria of Qualifying Facilities

[20] Under 220 CMR 8.02, "Qualifying Facility" means small power producers and cogenerators that meet the criteria specified in 18 C.F.R. §§ 292.203(a) and (b). This includes facilities under 80 MW that use renewable fuels or that meet certain co-generation efficiency standards.

including renewable energy and efficient co-generation. *5 Tr. 905; Exhibit AG-1 Rochester Gas & Electric Tariff Service Class 14 Section 3(c), Leaf 241.*

1. The Proposed Rates Are Not Consistent With Department's Regulations Applicable To Qualifying Facilities.

The Department has adopted regulations to establish the terms and conditions upon which a Distribution Company must provide service to a Qualifying Facility or an On-site Generating Facility. See 220 CMR 8.00 *et. seq.* "Qualifying Facility" means "small power producers and cogenerators that meet the criteria specified by FERC in 18 C.F.R. §§292,203(a) and (b)." 220 CMR 8.02.[21] 220 CMR 8.00 implements the provisions of the PURPA Sections 201 and 210, and regulations promulgated by the FERC in 18 C.F.R. 292.

The clear language of the regulations states that, upon request, a Distribution Company must supply a Qualifying Facility with service under rate schedules applicable to all customers, **regardless of whether they generate their own power**. 220 CMR 8.06(1) states as follows:

> "(1) Each Distribution Company shall, upon request by a Qualifying Facility or On-Site Generating Facility, supply to a Qualifying Facility or On-site Generating Facility supplementary, back-up, maintenance, and interruptible power pursuant to 18 C.F.R. 292.305(b) under rate schedules applicable to all customers, regardless of whether they generate their own power." *220 CMR 8.06(1)*

The language could not be more clear. NSTAR Electric must provide service to a Qualifying Facility under rate schedules applicable to all customers with similar voltage and load characteristics, regardless of whether they generate their own power. To the

[21] The Department regulations also apply to On-Site Generating Facilities, which are defined as "any plant or equipment that is used to produce, manufacture, or otherwise generate electricity and that is not a transmission facility and that has a design capacity of 60 kW or less." Thus by definition, the On-site generating Facilities are already exempt from the provisions of the Proposed standby rates.

extent that NSTAR Electric seeks to prevent Qualifying Facilities from being served under the otherwise applicable rates, it is in direct breach of the Department's regulations and the requirements of Federal law and regulations.

2. The Proposed Rates Violate PURPA and Federal Regulations.

Congress enacted PURPA in 1978 to encourage the development of alternative energy and cogeneration. *Cambridge* at 15. In *Cambridge*, the Department provides relevant background information noting that Congress realized that utilities might be unwilling or reluctant to provide back-up or supplemental service to Qualifying Facilities, and therefore required that rates for sale of such services be "just and reasonable and in the public interest" and "not discriminate against" Qualifying Facilities. *Cambridge* at 16, citing 16 U.S.C. s. 824a-3(c); *FERC v Mississippi,* 456 U.S. 751, 755 (1982). The Department went on to note that the question whether rates for standby service are just and reasonable, in the public interest, or discriminatory is a question of fact to be resolved by the Department. *Id. at 16.* The facts presented in this case clearly demonstrate that the rates proposed by NSTAR Electric are discriminatory against Qualifying Facilities. Moreover, the rates proposed by NSTAR Electric are not just and reasonable, nor are they in the public interest.

Regulations promulgated by the FERC establish legal standards for standby and maintenance rates for Qualifying Facilities. 18 C.F.R. §292.305(c). The NSTAR Electric proposed rates violate those standards. Consequently, the Department should not approve the NSTAR rates which are inconsistent with federal regulations. Therefore, NSTAR Electric proposed rates should be modified to exempt Qualifying Facilities.

a. The proposed rates improperly assume that all Qualifying Facilities will be out of service simultaneously at the time of system peak.

FERC regulation 18 C.F.R. §292.305(c)(1) provides that rates for standby service:

> (1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all Qualifying Facilities on an electric utility's system will occur simultaneously, or during the system peak, or both;

The regulation could not be more clear. The NSTAR Electric proposed rates clearly fail this test. Mr. LaMontagne testified that the Companies' distribution planners assume that all customer onsite generation will be out of service at the time of the distribution system peak. 1 Tr. 115, 117. This admission is not surprising since the assumption is necessary to support the bedrock foundations of the proposed rate – i.e. that the costs incurred to serve customers with distributed generation are the same as those incurred to serve all other customers. They justify this assumption -- simultaneous on-peak failure of all distributed generation -- on the argument that since they cannot control the dispatch of distributed generation, and since it is not 100% reliable, then they must assume for planning purposes that the distributed generation will be out of commission at any time, including during system peaks -- which is the only time that matters for system planning, cost incurrence and rate design. This assumed fact is underscored Mr. LaMontagne's testimony that if a standby customer seeks interruptible standby service, then the utility would not plan for or build distribution and transmission facilities to serve such a customer. *Exhibit NSTAR - HCL-1* at 26. Hence, the utility only incurs costs to serve standby customers when they are seeking firm service available at times of system peak.

The PURPA regulations provide a caveat: a utility may assume that all Qualifying Facilities will go down simultaneously and/or at the time of system peak if that assumption is supported by factual data. However, NSTAR Electric has not provided any factual data supporting its assumptions that all Qualifying Facilities will be out of service simultaneously at the time of system peak. Neither Mr. LaMontagne nor Mr. Salamone presented any load data regarding standby customers in his testimony. *2 Tr. 289-290.* While one might argue that factual data need not be empirical data, NSTAR Electric did not offer one scintilla of factual data to support their assumptions. Rather, NSTAR Electric's witnesses offered a hodgepodge of opinions and hypothetical speculations regarding when, where or why such a simultaneous failure at the crucial time of system peak may occur. But none of this amounts to either fact or data, and certainly not "factual data." Mr. Salamone, for example, offered several reasons why an onsite generation facility <u>may</u> be out of service, such as unplanned or maintenance outages. *Exhibit NSTAR-CPS-1* at 8. He testified that DG facilities <u>may</u> be shut down as a result of "high fuel prices, the opportunity to pursue fuel arbitrage options, maintenance scheduling and the unavailability of facility personnel". *Id.* at 9. However, on cross-examination, Mr. Salamone was unable to provide any facts regarding these opinions or even to explain how any of these stated reasons related to peak load conditions, which are caused by extreme weather. *7 Tr. 1274-1280.* Similarly, Ms. Parmesano offered a host of opinions and speculation why and how distributed generation might fail simultaneously, but she offered no factual data to support such an assumption. *Exhibit NSTAR HSP-1 at 12.* On cross-examination, when asked if she had any factual data or had performed any analysis to support the assumption that distributed generation systems might fail simultaneously, Ms. Parmesano answered: "I think its just common sense…" and went on to offer a series of hypothetical facts that could result in a simultaneous failure of DG. *6 TR. 1112*. Finally, Mr. LaMontagne agreed that while the loads of all requirements customers are driven by weather and business routines, it is not necessarily true that DG customers will require standby service at the same time that other customers are using the facilities. *2 Tr. 199.*

NSTAR Electric's admission that its rates are based on the assumption that all distributed generation, including all Qualifying Facilities will fail simultaneously and/or at the time of system peak is not supported by any "factual data" in the record, empirical or otherwise. The fact that NSTAR Electric claims the need to make such assumptions in order to plan their systems, does not mean that those assumptions are valid, reasonable, or most importantly, supported by factual data. NSTAR Electric has offered no factual data to support these twin assumptions, and therefore the rates run afoul of PURPA regulations affecting Qualifying Facilities.

This conclusion is supported by one of NSTAR Electric's own witnesses, Ms. Parmesano. In prior testimony offered in a case in Illinois regarding the propriety of a standby rate that accounted for different types of Qualifying Facilities, Ms. Parmesano testified that "to lump all QFs together and charge them rates based on assumptions about their class demands in high cost periods would not be just and reasonable and would be inconsistent with FERC regulations." *Exhibit AG 2-2 IP 1.6* at 11.

b. NSTAR Proposed Rates Violate PURPA Regulations Stating That Standby Rates Must be Non-Discriminatory.

PURPA requires that rates charged to customers with Qualifying Facilities cannot discriminate against such customers vis-à-vis customers with similar load characteristics. FERC regulations implementing Section 210 of PURPA set forth the requirements for the design of non-discriminatory rates as follows:

> Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics. (FERC Order 69, 18 FCR Part 292.305 (a)(2)).

On cross-examination, NSTAR Electric's witness Ms. Parmesano testified as to her interpretation of this provision, stating that if NSTAR Electric's standby rates did not apply to other customers with similar load and cost-related characteristics, then the "FERC would think they are discriminatory." *6 TR 1093*. She also agreed that in order for standby rates to be considered non-discriminatory by FERC, they must be based on accurate data. *Id.*

To the extent that the standby rates do not apply to other customers of NSTAR Electric with similar load and cost-related characteristics, they are inconsistent with PURPA. A review of the load data presented in this case demonstrates that there are many customers with so-called "intermittent" loads who would not be subject to the proposed rates. This fact is discussed in detail in Section I.A.2 above in this brief. Moreover, on cross-examination, Ms. Parmesano argued that contract demand rates should apply to customers with intermittent loads, regardless of whether they had distributed generation or not. *6 Tr. 1090-1092.*

In addition, to the extent that the proposed standby rates are not based on accurate data, then they are inconsistent with PURPA. NSTAR Electric's rates are dependent on the assumption that NSTAR is not recovering sufficient revenues from customers with distributed generation due to the "intermittent and infrequent" nature of the demands that standby customers impose on the distribution system. *Exhibit NSTAR-HCL-1* at 16. NSTAR offers no data whatsoever, accurate or not, to support the contention that the load profile of a customer with distributed generation is appreciably different than a similarly situated customer without DG. Rather, NSTAR makes hypothetical arguments about what one "would expect to see" if one did analyze the data. *Exhibit NSTAR-HCL-2* at 14-15. In fact, Mr. LaMontagne testified that "the actual load pattern of the customer with on-site generation provides no additional information needed for pricing the standby service." *Exhibit NSTAR-HCL-1* at 11.

B. <u>The Availability Clause</u>

The availability clause of the proposed rates states that the rates shall apply to customers who satisfy certain conditions. One of those conditions is as follows:

> 2. The customer (a) normally satisfies at least 20% of its maximum internal electric load from generating unit(s) with a combined nameplate rating greater than 60 kW ("Generation Units"), or (b) has installed generation unit(s) with a combined nameplate rating greater than 500kW. . .

Exhibit NStar HCL-10.

The Department should order the Companies to modify this provision in three ways.

1. Change The Conjunction Separating Clauses (a) And (b) From "Or" To "And".

As written the proposed rates apply to generation units which either satisfy at least 20% of the customer's load or have a nameplate rating greater than 500kW. As Ms.

Saunders explained, the clause describes which customers are subject to the proposed rates, not which customers are excluded. *6 Tr. 1024-1025.*

Ms. Saunders testified that this provision should be rewritten to replace the conjunction "or" with "and". *6 Tr. 1022.* For example, if a small customer with a total load of only 200 kW installed a 100 kW generator, it would be subject to the proposed rates because the ratio of 100 kW to 200 kW is greater than the 20% threshold, even though the customer's total load is well below 500 kW. *6 Tr. 1022-1023.*

With respect to the 500 kW limitation, a 1 MW customer that installed a 100 kW facility would also be subject to the standby rate, even though the customer's facility represents only 10% of its total load, well within what the Companies have testified is the normal range of variability. *1 Tr. 22.* Accordingly, the Department should modify the availability clause by substituting "and" for "or".

2. The 20% Threshold Should Be Increased to 50%.

The 20% threshold is inconsistent with the Companies' own testimony. Mr. LaMontagne testified that the 20% threshold is based on the Companies observation that medium and large commercial and industrial customers exhibit "normal variability" in the range of 70% to 90%. *1 Tr. 22.* These observations are based on the histograms included as Exhibit NStar-HCL-8. *Id.; 7 Tr. 1201.* In particular, the 70% to 90% range refers to the 0.7, 0.8 and 0.9 deciles shown on those histograms. *7 Tr. 1202.* Thus, according to the Companies' own testimony, customers falling in the 0.7 - 0.9 deciles exhibit normal variability.

Customers in the 0.7 decile represent customers whose ratio of average billing demand to maximum billing demand is in the range of greater than 0.6 to less than or equal to 0.7. *See 7 Tr. 1204* (customer with ratio of average to maximum demand of 0.26 included in the 0.3 decile). Therefore, according to the Companies' own testimony, customers with a ratio of average billing demand to maximum demand greater than 0.6, would be in the range of normal variability of medium and large commercial and industrial customers. This ratio corresponds to a threshold value of 40%, not 20% as proposed by the Companies. Therefore, based on the Companies own testimony, the threshold should be increased to at least 40%.

Moreover, the Companies claim that the normal variability is in the range of 70% to 90% is not supported by Exhibit NStar HCL-8. That exhibit shows that only 76% to 77% of Boston Edison's medium and large commercial and industrial customers fall in the range of 70% to 90%. *7 Tr. 1202.* By contrast, 96% to 97% of customers on Boston Edison's Rates G-3 and T-2 fall within the 60% to 100% range. *Id.* Based on the data presented in Exhibit NStar HCL-8, the normal range of variability of these customers is 60% to 100%, rather than 70% to 90% as stated by the Companies.

Customers in the 0.6 decile have a ratio of average to maximum billing demand of greater than 0.5. Therefore, based on the data presented in Exhibit NStar HCL-8, the appropriate threshold for the proposed rate should be 50%, not 20% since this threshold captures the normal variability of these customers.

A 50% threshold is consistent with the rate proposed by Boston Edison and approved by the Department in D.P.U./D.T.E. 92-92. In that case, Boston Edison proposed a reservation charge for customers with sporadic or intermittent loads of significant magnitude. *D.P.U./D.T.E. 92-92* at 58.

> In particular, such charge would apply when: (a) the annual maximum billing demand exceeds the average of the 11

> billing demands by 500 kW or more; (b) the seasonal maximum demand in both the summer and the winter billing periods is more than twice as high as the average of the other billing demands in each season.

Id.

Under this rate, customers were assessed for sporadic or intermittent loads when two conditions were true. First, the maximum demand had to exceed the average demand by at least 500 kW. Second, the seasonal maximum demand in both the summer and winter had to be at least twice as high as the average of the other billing demands. This latter provision effectively represents a 50% threshold.[22] Accordingly, a 50% threshold corresponds to charges for intermittent loads as previously proposed by Boston Edison and approved by the Department.

Based on the foregoing, the Department should order the Companies to modify the proposed threshold to 50%.

3. The 500 kW Threshold Should Be Increased to 1 MW.

The Companies stated that they set the threshold availability at 500 kW because "at that level the distribution system planners generally take specific consideration of the load served by customer generation when designing capacity requirements for distribution circuits". *Exhibit D.T.E. 7-5.* However, no such threshold is addressed in the testimony of the Companies' system planning engineer. *7 Tr. 1371-1319.* Mr. Salamone testified that for planning purposes the Companies' system planners use a threshold of 1 MW. *7 Tr. 1319.* Specifically, the Companies add known load additions greater than 1 MW to their econometric forecast in planning the Companies' distribution system. *7 Tr. 1347.*

---

[22] Boston Edison Company's proposed charges for sporadic service were $1.15 per kW at high tension and $1.85 at secondary.

When asked about the 500 kW threshold on cross-examination, Mr. Salamone gave a convoluted answer involving some vague "second process" employed by the Companies to determine whether a new customer may be connected to a particular circuit. *7 Tr. 1317-1319, 1347-1349.* He was not able to give any specifics about the alleged 500 kW threshold process, nor was he able to identify any specific procedures used by planners which considered the 500 kW threshold. *Id.* Mr. LaMontagne could not provide any justification for the 500 kW threshold either. *7 Tr. 1349.*

Based on the testimony of the Companies' witnesses, there is no planning basis for a threshold of 500 kW. The only reference in the testimony is to a 1 MW value used for known load additions (as opposed to DG) in the Companies' peak load forecast. Therefore, based on the Companies' testimony, the 500 kW threshold should be increased to at least 1 MW.

C. The Contract Demand Should Be Based On The Customer's Largest Generating Unit.

NSTAR Electric proposes to set the contract demand equal to the generating capability or the expected output of the customer's generating units. *Exhibit NStar HCL-10, p. 2 of 5.* Ms. Saunders testified that setting contract demand in this way overstates the amount of standby service that is required by customers with multiple generation units, because the likelihood of all units failing at the same time is small. *Exhibit TEC-1* at 10. She further testified that the greater the number of units at a customer's premises, the greater the reliability of those units. *Id.; Exhibit DTE/TEC 1-3.* Ms. Saunders testified that this increased reliability should be quantified and the contract demand should be reduced accordingly. *Exhibit TEC-1* at 10.

Mr. LaMontagne acknowledged that a customer with multiple generating units may have increased reliability. He stated that the Companies are willing to reach mutual arrangements with a customer regarding the amount of firm standby capacity they actually require. *Exhibit NStar-HCL-7.* However, he stated that these situations would be limited to where a customer is willing to hold one or more of its units in reserve for backup purposes. *Id.* at 26-27. In other words, the Companies would not count the nameplate capacity of backup generating units which are not normally used to serve the customer's internal load requirements. This proposal does not address the reliability inherent in multi-unit arrangements. It merely reflects that the Companies would not count emergency generation in determining the contract demand.

Mr. LaMontagne stated that the Company "designed its system to support customer load when the largest generating unit is unavailable". *Exhibit NEDGC 2-3.* Mr. Salamone testified "we generally don't assume that two or more units would be out of service at the time that we would call for their dispatch." *8 Tr. 1978.* Since the Companies state that they design their system to provide capacity to backup the largest generating unit, this consideration should be reflected in the standby rates. In the case of a multiple unit facility, the contract demand should be limited to the capacity of the largest available generating unit, because that is the capacity the Companies claim they take into account in designing distribution facilities.

Accordingly, the Companies' proposed tariffs should be revised to provide that, in the case of multiple units, the contract demand will be set equal to the capacity of the largest generating unit.

D. <u>The Demand Charges Should Be Reduced To Full Marginal Costs.</u>

The Companies based their proposed demand charges for standby and supplemental service on the demand charges contained in the otherwise applicable rate schedules. The record in this case demonstrates that the otherwise applicable rates are roughly double both the embedded revenue requirement and the marginal cost of providing service. *2 Tr. 235-241, 244-246.*[23] Accordingly, setting rates for DG customers based on the otherwise applicable rates violates both the fairness and economic efficiency objectives. This would result, not only in DG customers subsidizing other customers, but also it would lead to incorrect and inefficient decisions by customers about whether to install DG.

In *Cambridge,* the Department held that in the absence of any cost or load data specific to standby service (which data would enable the determination of a revenue requirement for standby customers,) standby service rates should be based on marginal costs. *Cambridge* at 45-46. In this case, the Companies did not present any load or cost data for DG Customers. Instead, they propose to base their proposed rates on the otherwise applicable rate schedules.

The Department should order the Companies to reduce the distribution demand charges for standby and supplemental demand in their proposed rates to the level of marginal costs, as most recently approved by the Department. Mr. LaMontagne and Ms. Saunders testified that the marginal costs for customers on Boston Edison rates, G2 and T2 is $8.96 in the summer, and $5.71 in the winter. *2 Tr. 234-235; Exhibit TEC 2-2.* They further testified that marginal distribution costs for Boston Edison's rates G3 is $5.29/kW in the summer, and $3.68/kW in the winter. *2 Tr. 243; Exhibit TEC 2-2.*

[23] See Section I.B.2 *infra.*

The Department should order the Companies to reduce their standby and supplemental demand charges to the level of marginal costs.

E. The Contract Demand Should Be Credited Against The Supplemental Demand Every Month.

Under the Companies' proposed rates, the DG customer would receive a credit against its metered supplemental demand to the extent that the customer's generation is reduced at the time of the customer's monthly maximum demand. *Exhibit NStar-HCL-1* at 22. The credit would be equal to the difference between the contract demand and the customer's actual generation at time of its monthly peak. *Id.* However, the credit would only apply in those months when the customer's onsite generation is out of service at the time of the monthly maximum demand. If generation is out of service at any other time during the month or is not out of service at all, the customer is charged the full standby charge based on the contract demand and the full supplemental charge based on the maximum demand as measured at the customer's meter. *2 Tr. 301-302, 314.*

The Companies propose to give the customer a credit against its contract demand because the customer already paid for that capacity as part of the contract demand charge. *2 Tr. 302.* In fact, the customer is paying the same standby charge in every month. *2 Tr. 301.* Since the customer is paying for capacity equal to the contract demand every month, the customer should receive a credit against its supplemental demand for the full amount of the contact demand each month.

This modification would give the customer credit for the contract demand capacity for which he is paying each and every month of the year. It would also address the Companies' claim that it is not receiving sufficient revenue to cover the costs of standby capacity. *2 Tr. 312.* The effect of this modification would be to convert the

Companies' proposed standby charge to a minimum charge. Mr. LaMontagne agreed that the Companies "might set the minimum charge at the level of the contract demand, which is based on the level of the onsite generation capacity and charged that every month. *2 Tr. 313.* He testified that it would be possible to have a minimum charge using the same kind of rate structure but simply giving the customer credit in each month for the amount of standby capacity the customer is paying. *2 Tr. 314.*

Under this modification, DG customers would receive credit for the actual amount of contract demand for which they pay each month against their supplemental demand. This alternate rate structure would give DG customers credit for the amount of capacity for which they are paying each month. It would also provide the Companies with a minimum charge to address its concerns regarding the amount of revenue received from standby customers. It would also eliminate the need to meter the customer's generation.

Accordingly, the Companies' proposed standby rates should be modified by requiring that the full amount of contract demand be deducted from the supplemental demand in each month.

F. The Supplemental Demand Should Be Adjusted When Customers with Distributed Generation Are Forced Offline Due To Faults or Other Disturbances on the Distribution System.

The provisions of the rates proposed by NSTAR Electric governing the measurement of supplemental demand should be modified to state that peak demands shall not be measured or established during the 24 hour period immediately following a disturbance on the Company's distribution system that causes the customers distributed generation to trip off line. *Exhibit NEDGC-3-* at 11. The reason for this provision is to prevent NSTAR Electric from benefiting from increased demand charges that it has ultimate control over.

G. Special Contracts Should Be Available For Customers With Large Or High Voltage Facilities.

For customers with large distributed generation facilities of 1MW or more, the customer should have the option of pursuing a special contract regarding the provision of standby service or other related services from the distribution company. Large DG installations often present a unique set of facts and circumstances that need to be addressed in the negotiation of standby and other related services. In many situations, the DG installer will be required as part of the interconnection process to pay for upgrades to the distribution system necessary to accommodate the DG system. These policies are dictated as part of the distribution company's line extension policy as well as the interconnection standards. See NSTAR Electric Interconnection Standards; Qualifying Facilities Regulations at 220 CMR 8.00 *et. seq.*; Appendix B of NSTAR Electric's Terms and Conditions. These contributions known as "Contributions in Aid of Construction" can be substantial and should be accounted for or credited against any applicable standby charges. For example, MIT paid NSTAR $1.45 million for the full cost of interconnecting its 20+ MW DG system to the NSTAR system in Cambridge to the specific facts and situation in question. *Exhibit TEC-1* at 8.

Moreover, very large facilities can offer benefits to the distribution system that could be reflected in a special contract that accounts for the costs and benefits provided. Finally, customers installing larger DG systems are more likely to have the resources necessary to support direct negotiations with the distribution company regarding the procurement of standby and other related services.

NSTAR Electric should be required to respond to any request for a negotiated rate within sixty days of receipt of the request for special contract with a written draft of an agreement. The terms should be subject to negotiation, but should include some of the following parameters: (1) the negotiated rate should be based on the marginal costs incurred by NSTAR Electric in providing the service requested, less a credit for any amounts contributed by the customer installing the distributed generation system; and (2) the contract should also recognize benefits that the DG provider can provide to the distribution system. In any case, the Department should assign a staff member or hearing officer to be able to resolve negotiation issues in case the parties reach an impasse.

H. The Rates Should Include an Expanded Grandfather Clause, Exempting all Distributed Generation that is Permitted, Designed and Funded Prior to the Effective Date of the Tariff.

The grandfather clause of the proposed rates should be expanded to include systems that are permitted, designed or funded prior to the effective date of the tariff. Testimony of several witnesses in the case suggested that distributed generation systems may take up to a year in planning, design, permitting, construction, etc. *3 Tr. 418-420; 5 Tr. 944; Exhibit JS-DH-1* at 8-9. For systems that are already substantially in process, they were planned at a time when the rates were the otherwise applicable rates. *3 Tr. 418; Exhibit NEDGC-3* at 12; *Exhibit JS-DH-1* at 8-9. While Mr. LaMontagne testified that customers should have been on notice that the rates were subject to change, it is not appropriate to make customers subject to the uncertainty of new potential rules, for then future conduct will be chilled by uncertainty. Moreover, it is appropriate to allow prudent planning to go forward and avoid a rush to meet an artificial deadline. That said, customers who are grandfathered under any adopted rate should be required to complete construction of their systems within twelve months of the effective date.

I. Section II Conclusion

In conclusion, the Department should order the proposed rates be modified in accordance with the preceding suggestions, regardless of whether the proposed standby rates are offered as an optional or an exclusive service.

III. THE DEPARTMENT SHOULD REJECT NSTAR ELECTRIC'S PROPOSAL TO OFFER NON-FIRM STANDBY SERVICE ON AN INTERRPUTIBLE BASIS AND ORDER THE COMPANY TO OFFER OPTIONAL DISPATCHABLE GENERATION SERVICE.

A. The Department Should Reject NSTAR Electric's Proposal Regarding Non-Firm Standby Service.

In opening this investigation, the Department stated that it would investigate whether distribution companies should offer "non-firm" standby service. *NStar Electric,* D.T.E. 03-121, p. 1. (January 20, 2004)(Notice of Public Hearing and Procedural Conference). Mr. LaMontagne testified that the Companies would be willing to enter into a negotiated contract for non-firm interruptible service. *Exhibit NStar-HCL-1* at 26. Under the Companies' proposal, the customer would be billed on an as-used basis under the otherwise applicable rate schedule for any service actually taken. *Id.* The Companies did not offer any other terms for a non-firm arrangement stating that the terms would be negotiated on a case-by-case basis. *Id.* at 27.

Mr. LaMontagne testified that the Companies believe that non-firm service would require the customer to request standby delivery when its generation facilities are unavailable. *Id.* The Companies would have a limited time (30 minutes) to respond to the customer indicating whether or not distribution system capacity was available. *Id.* Further, if the Companies subsequently determined that previously available capacity was no longer available, they would notify the customer with instructions to interrupt standby load within 30 minutes of notification. *Id.*

The Companies proposal is unacceptable and unworkable for several reasons. First, the Companies propose to offer “non-firm” service under the otherwise applicable rate schedule. Under this construct, customers with similar load profiles would face vastly different rates. Customers without DG would receive firm service, customers with DG would receive non-firm service. For the reasons stated in Section I above, there is no basis to treat these customers differently and the Department should require the Companies to provide firm standby service under the otherwise applicable rate schedule. Consequently, the otherwise applicable rate schedule is not an appropriate basis for a so-called “interruptible” rate.

Second, the Department should not permit the Companies to negotiate non-firm service on a case-by-case basis except perhaps for larger DG installation as discussed in Section III.G below. Although special contracts are subject to review and approval by the Department, that process presupposes that the Companies and the customer will be able to reach an agreement on the terms of the special contract. Mr. LaMontagne testified that the Companies do not have any parameters or time limits within which to conduct such a negotiation. *7 Tr. 1192-1193.* Since the Companies are the sole supplier of service, they possess a superior bargaining position with respect to any negotiated contract. They could very well assume a “take it or leave it” position. In such a case, the customer would have little or no recourse.

Third, the Companies' proposal is unworkable as a practical matter. It assumes that customers with onsite generation have the ability to curtail their load. While this may be an option for some DG customers, it is clearly unworkable for a DG customer, such as an office building, hospital or school, which requires continuous electric service.

B. <u>The Department Should Order NSTAR Electric to Offer an Alternative "Dispatchable DG" Service Rate.</u>

We demonstrated in Section I above why in the absence of a full COS for the standby class, the proper and appropriate rate for firm standby service is the otherwise applicable rate. Therefore, to the extent a standby customer is willing to commit to keeping their DG system on and running during times of peak system load, the DG customers should receive a credit from the companies for providing a benefit back to the distribution company by increasing the available system capacity at time of peak load.

The parties have agreed that under certain circumstances, that DG can provide benefits directly to the Companies by allowing the companies to defer system upgrades. This benefit should be reflected in a credit to be added to the customers who can and choose to provide such benefits. NSTAR's expert witness Ms. Parmesano conceded that an accurate calculation of the costs of DG must be net against the benefits that DG provides to the distribution system, and that a standby rates design that does not take such benefits into account where applicable, "would be too high." *6 Tr.* at 1086-87. Moreover, Mr. Casten offered a methodology for the calculation of such benefits, particularly with regard to the deferral of distribution system capacity. *Exhibit DTE-NEDGC 1-7.*

Mr. LaMontagne and Mr. Salamone conceded that distributed generation could provide a benefit to the Companies and their customers if the Companies could control the dispatch of distributed generation. *7 Tr.1434-1435,1450-1452,1498-1500.* In particular, they recognized that the Companies could defer future distribution investment if they had control of the dispatch of DG units. *Id.*

The Department and the Companies have previously addressed the control of voluntary customer actions in the context of interruptible rates. Cambridge Electric Light Company's Large General Interruptible Service, Rate I-1, provides an example. *Exhibit NEDGC 2-13(a)*. Under Rate I-1, the customer elects an amount of load that it is willing to make available for interruption ("interruptible load"). The customer also elects the maximum number of interruptions per year and the maximum cumulative interruptible hours per year. Subject to these parameters, the customer agrees that the Companies may, at their sole discretion, at any time upon 30 minutes notice to the customer, interrupt the customer's interruptible load. *Exhibit NEDGC 2-13(a), p. 1 of 6.*

In consideration of the customer's agreement to interrupt load at the Companies' request, Rate I-1 provides the customer with a credit per kVA to be applied to the customer's distribution and transmission demand charges under the Companies' otherwise applicable rates. *Id.* at p. 3 of 6. *7 Tr. 1193.* Rate I-1 also imposes a penalty if the customer fails to interrupt its interruptible load, equal to at least 70% of the interruptible load within 30 minutes of being required to do so, or fails to maintain such load interrupted during the interruptible period. The penalty has two parts. First, the amount of load the customer nominated for interruption is reduced to the actual amount of the interruption for a period of twelve months. Second, a charge is added to the customer's bill for the following month equal to the 70% of the difference between the nominated interruptible load and the actual interruptible load multiplied by the applicable credit per kVA times the number of months, to a maximum of six months, since the last change in the level of the customer's nominated interruptible load. *Id. 7 Tr. 1194-1196*

The provisions of Rate I-1 illustrate how the Companies can control the voluntary behavior of a customer through credit and penalty provisions. The same type of control can be exhibited over a DG customer under an optional rate for dispatchable generation service. An illustrative tariff for Optional Dispatchable Generation Service ("Rate DG-1") is provided as an appendix to this brief.

Rate DG-1 is modeled after Rate I-1. Under Rate DG-1, the customer would continue to take service for all purposes under the otherwise applicable rate schedule. As in the case of Rate I-1, the DG customer under Rate DG-1 would nominate an amount of generation it is willing to make available for dispatch at the Companies' request. The customer could nominate an appropriate amount of dispatchable generation based on the configuration of the customer's generating units. Because Rate DG-1 is optional, the customer would not have to nominate any generation as available for dispatch, in which case the customer would receive no credit for its generation. The customer could nominate any amount of generation for dispatch up to the expected output of its generating facility. Thus, for example, a customer with four generating units may choose to nominate generation equivalent to three of its units to ensure that generation would be available when called upon by the Companies.

Also, as in the case of Rate I-1, customers under Rate DG-1 would elect a maximum number of times the Companies could request dispatch during the year and a maximum cumulative number of hours of dispatch. Each dispatch period would be limited to 8 hours.

The customer would agree to dispatch its generation up to the nominated level on 30 minutes notice from the Companies. The Companies would verify that the customer, in fact, dispatched its units by metering the customer's generation. So long as the customer dispatched its unit in accordance with the provisions of the rate, the customer would receive a credit to be applied against its distribution charges under the otherwise applicable rate. If the customer failed to dispatch its units, it would incur a penalty. First, the amount of its nominated dispatchable generation would be reduced to the actual generation during the dispatch period for twelve months. Second, the customer would pay a penalty equal to 70% of the difference between its nominated dispatch and its actual dispatch times the amount of the credit for a period of up to six months since the last time the nominated level of dispatch changed. All of these provisions are analogous to those in Rate I-1.

Proposed Rate DG-1 also requires the customer to schedule maintenance with Companies. The customer's generation would not be available for dispatch during the scheduled maintenance period and the Companies would not be permitted to call on the customer's generation units during the scheduled maintenance period.

Rate DG-1 would be available to all DG customers. There would be no "grandfathering".

Rate DG-1 would provide the Companies with the ability to control the dispatch of DG units and thereby defer distribution investment. The dispatch of the DG units is verifiable because the Companies would meter the output of the customer's generation. The customer is provided with an incentive and a penalty to ensure that its units are available for dispatch at the Companies' request.

In Rate DG-1, the Companies' reported avoided cost of distribution is used to determine the size of the credit to be given to DG customers who make their units available for dispatch. *Exhibit D.T.E. 6-3; 8 Tr. 1428-1435.* Specific values for each of the NStar Electric distribution companies could be substituted. *Record Request TEC-4.* Alternatively, the marginal cost of distribution could be used as a basis for the credit.

The proposed Rate DG not only addresses the Companies' concerns regarding control over the dispatch of the customer's facilities, but also addresses the problems noted above from the perspective of the DG customer. First, if the customer agreed to make its generation available for dispatch, it would receive an effective price lower than the otherwise applicable rate schedule because the customer's charges under the otherwise applicable rate schedule would be reduced by the amount of the dispatchable generation credit. Second, the use of a dispatchable generation rate avoids the need to negotiate with the Companies on a case-by-case basis. The rate would be available to all DG customers who satisfy the availability clause. Third, Rate DG-1 avoids the practical problem of a DG customer having to curtail load. Under Rate DG-1, rather than curtailing load, a customer would make its DG facilities available for dispatch. Under the terms of the rate, there would be no interruption of service to the customer's load requirements.

Based on the foregoing, the Department should order NStar Electric to offer an optional dispatchable generation service to DG customers.

CONCLUSION

For the foregoing reasons, the department should reject the proposed rates as filed and rule that customers with distributed generation should have the option of remaining on the otherwise applicable rates. The Department should adopt optional standby rates with all the modifications proposed in Section II that DG customers may elect to take. In the alternative, the Department should order the Companies to modify the proposed rates as discussed in Section II. Finally, the Department should reject the non-firm interruptible standby service as proposed to be offered by the Companies and order the Companies to offer optional dispatchable generation service as described in Section III.

____
Roger M. Freeman
Robert M. Granger
FERRITER SCOBBO & RODOPHELE, PC
125 High Street
Boston, MA 02110
(617) 737-1800

Date: June 4, 2004

Q:\rmf\Standby Rates\Initial Brief - Final.doc

APPENDIX

OPTIONAL DISPATCHABLE GENERATION SERVICE

RATE DG-1

AVAILABILITY

This rate is available to any Customer who executes a Dispatchable Generation Service Agreement with the Company and who satisfies the following conditions:

1. The Customer qualifies for service on Rate G-2, T-2 or G-3 based upon its internal load requirements.

2. The Customer normally satisfies all, or a portion of, its internal electric load from generation unit(s) with a combined nameplate rating greater than 60 kW ("Generation Units"), where electricity provided by the Generation Units is not delivered over Company-owned facilities under an applicable retail delivery tariff.

3. The Customer is willing to make its Generation Units available for dispatch ("Dispatchable Generation") in accordance with the terms of this rate.

Electricity delivered by the Company, including service to the satisfy the Customer's internal electric load when the Generation Units are not supplying all of the Customer's internal electric load requirements, shall be billed under Rate G-2, Rate T-2 or Rate G-3, subject to the Dispatchable Generation Credit provisions of this rate as applied to the Dispatchable Generation.

Service under this rate is available for all use at a single location on contiguous private property subject to the availability and billing provisions of the rate schedule under which the Customer's electric load would be served absent the supply provided by the Generation Units ("Applicable Rate Schedule"). The electricity supplied to the Customer shall be measured through one or more meters as determined by the Company. The Customer must furnish at its expense a connection whereby the Company can meter the power supplied by the Generation Units. All meters shall be owned, operated and maintained by the Company.

OPTIONAL DISPATCHABLE GENERATION SERVICE

RATE DG-1

DISPATCHABLE GENERATION OPTIONS

Dispatchable Generation is the amount of generation in kW which the Customer agrees to dispatch at the Company's discretion at any time (other than periods of scheduled maintenance) upon 30 minutes notice to the Customer. No single request for dispatch shall exceed 8 hours in duration, nor shall there be more than one request for dispatch on any single calendar day. The Customer may elect one or more of the following options.

Option	Maximum Number of Dispatch Requests Per Year	Maximum Cumulative Dispatchable Hours Per Year
A	60	360
B	40	240
C	20	120

DISPATCHABLE GENERATION CREDIT PER MONTH

The sum of the Customer's Distribution Demand Charge and Distribution Energy Charge, if any, per month under Rate G-2, Rate T-2 or Rate G-3 shall be subject to a dispatchable generation credit determined by multiplying the Nominated Dispatchable Generation ("NDG") by the applicable credit per kW set forth below:

Option A	$11.00 per KW
Option B	$ 7.33 per KW
Option C	$ 3.67 per KW

Issued by: Thomas J. May
President

Filed:
Effective:

OPTIONAL DISPATCHABLE GENERATION SERVICE

RATE DG-1

FAILURE TO DISPATCH

If at any time (other than periods of scheduled maintenance) a Customer providing Dispatchable Generation Service fails to dispatch an amount of generation equal to at least 70% of the NDG within 30 minutes of being requested to do so by the Company or fails to maintain such generation during the Dispatch Period, the following penalties shall be applied:

A. The NDG will be reduced to the Actual Dispatchable Generation ("ADG") for a period of 12 Months.

B. A charge will be added to the Customer's bill for the following Month equal to the difference between 0.70 times the NDG and the ADG multiplied by the applicable Credit per KW as calculated above times the number of Months, to a maximum of 6, since the last change in the level of the NDG.

SCHEDULED MAINTENANCE

The Customer will schedule maintenance of its Generation Units in accordance with the following provisions: (1) maintenance is not scheduled during the Peak Period of the months January, July, August and December; (2) unless specifically approved by the Company, maintenance will not be performed for more than 4 consecutive weeks per request; (3) the Customer provides the Company with a preliminary written maintenance schedule by December 1 of each year; (4) the Company approves the maintenance schedule; and (5) the Customer provides written notification to the Company of the dates and duration of the outage 30 days prior to the actual outage.

OPTIONAL DISPATCHABLE GENERATION SERVICE

RATE DG-1

SPECIAL PROVISIONS

A. Upon written request of the Company, the Customer shall install, maintain and bear the cost of such telemetering equipment and data circuits as the Company may reasonably require for the transmission of various metered values to its operations center. The design of and equipment specifications for such telemetering equipment and data circuits shall be approved by the Company prior to installation thereof by the Customer.

B. Upon written request of the Company, the Customer shall provide a telephone module, dedicated solely to the purpose of communicating with the Company, with both audible and visual alarms to ensure prompt and effective response to the notification by the Company. Telephone calls to and from the Company's System Control Center will be recorded.

DEFINITIONS

Dispatchable Generation. The Dispatchable Generation shall be the amount of generation that a Customer electing service under the provisions of this rate offers for dispatch.

Actual Dispatchable Generation ("ADG"). The ADG shall be actual amount of generation provided by the Customer during the Dispatch Period, measured in kW, on the Company’s meter(s) recording the output of the Customer’s Generation Unit(s).

Dispatch Period. A Dispatch Period shall begin when the Customer is given notice by the Company to generate the NDG and shall end when the Company notifies the Customer that the period of dispatch is over; provided that no Dispatch Period shall exceed 8 hours.

Nominated Dispatchable Generation ("NDG"). The NDG shall be the amount of generation in KW which the Customer agrees to supply within 30 minutes of notice by the Company.

Issued by: Thomas J. May
President

Filed:
Effective: